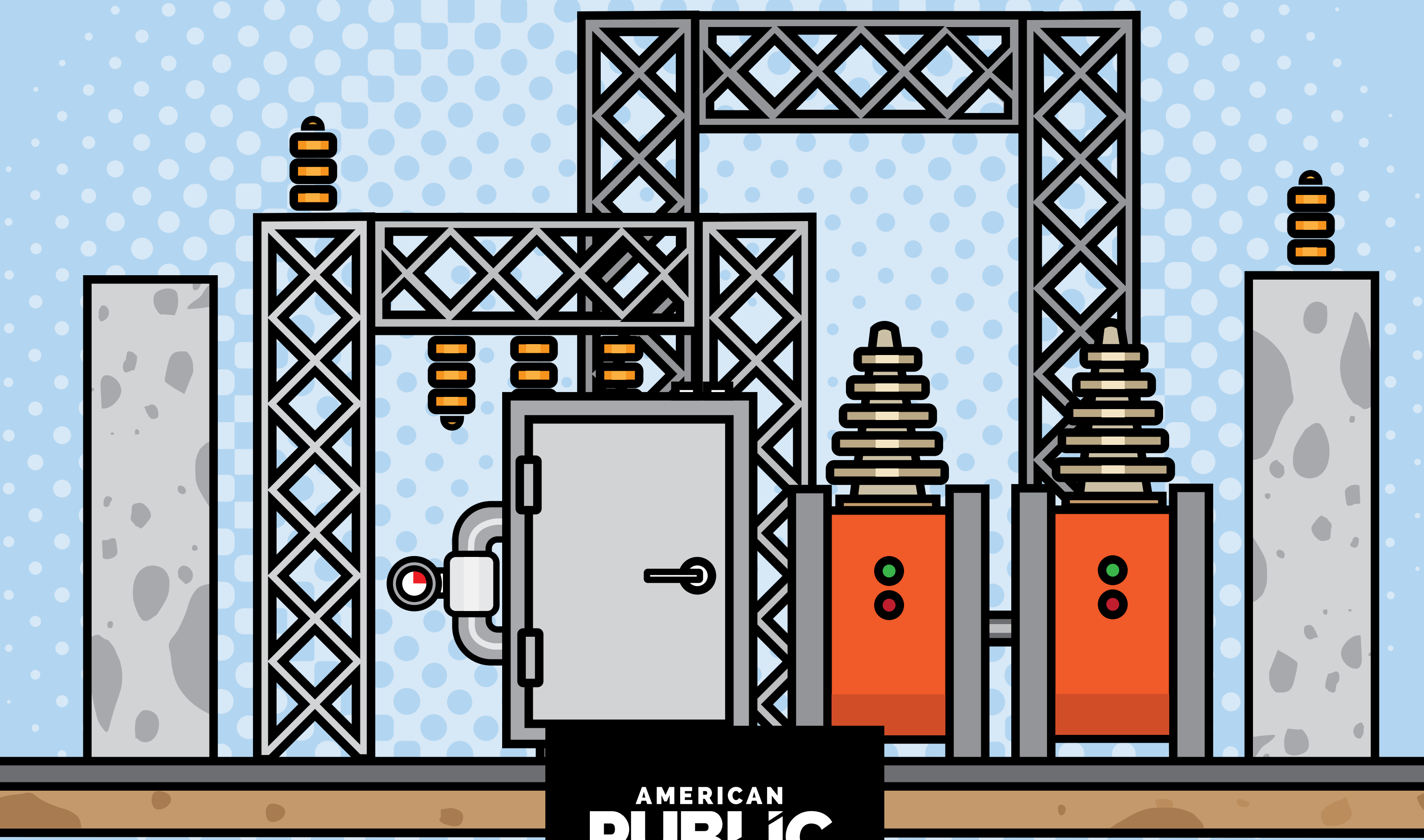
# 2020 DISTRIBUTION SYSTEM RELIABILITY & OPERATIONS SURVEY REPORT



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## NOTE

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# INTRODUCTION

The Distribution System Reliability and Operations Survey Report is intended to help members of the American Public Power Association (APPA) understand and analyze the issues that arise from maintaining and operating an electric distribution system. The survey is intended to shed light on general factors public power utilities use to make decisions regarding reliability and operations. The information on distribution system operations contained in this report is designed to provide public power utilities with a broad base of knowledge for formulating easy-to-administer and sound day-to-day practices. APPA members can access this report for free to serve as a supplemental tool to expand industry-wide understanding of the procedures and practices that lead to reliable distribution system operations.

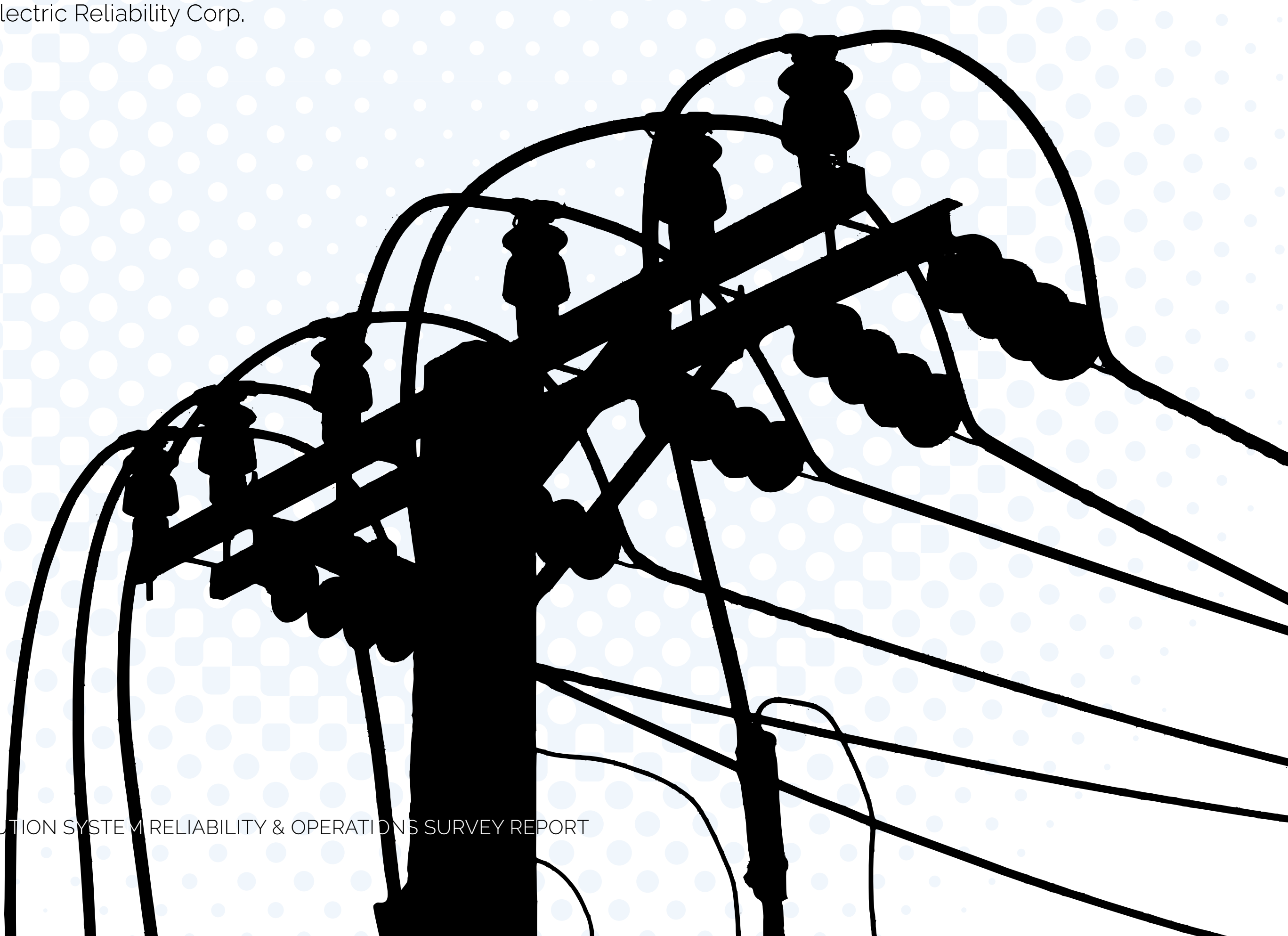
This report does not address reliability of the bulk power system. The bulk power system is defined by the Federal Energy Regulatory Commission and is subject to reliability standards established through the North American Electric Reliability Corp.

In many cases, municipally owned utilities are not subject to federal or state laws regarding the reliability of their distribution systems. This means that decisions regarding utility distribution system operations and the resultant degree of reliability are inherently local.

This report summarizes survey results in seven areas:

1. Outage Tracking
2. Power Quality
3. Outage Prevention and Restoration
4. Workforce
5. System Operation
6. Construction Design
7. General Utility Information

The survey requested certain confidential or proprietary information that may be sensitive. All responses included in this report have been aggregated and anonymized to ensure confidentiality.



# DISCUSSION

It's important to understand the context for the data analysis presented and a few fundamental questions surrounding distribution system reliability.

## System Reliability

Reliability, from a system engineering perspective, is the ability of an electric system to perform its functions under normal and extreme circumstances. Reliability indices help engineers and other operations personnel understand and demonstrate the interconnected nature of the system components that make up an electric distribution system. This connection makes apparent that overall system design, including construction practices and fusing schemes, affects reliability. Among the commonly considered factors are: system voltage, feeder length, exposure to natural elements (overhead or underground conductor routing), sectionalizing capability, redundancy, conductor type/age, and number of customers on each feeder.

Since resources are typically limited, reliability-related system improvement decisions involve tradeoffs. In some cases, improving system redundancy is the most important enhancement that can be identified through reliability studies. Additional redundancy can lead to resiliency, or the ability to recover from larger shocks to the system, which can improve reliability during extreme events and catastrophes. In preparation for these events, key tradeoffs are made between cost, transport efficiency (e.g., line losses), and fault tolerance.[1] Knowing where to start when making these important decisions can be a difficult task. Engineers and other operations personnel at utilities that collect reliability indices will have better data to inform these decisions.

Another area of tradeoffs is line design. For instance, when looking at line voltage, if an engineer decides to use a lower voltage 4-kilovolt line, then the line might experience fewer outages from contact with vegetation. However, with lower voltage, the thermal line losses will be greater, and the system will be less thermally efficient. On a line designed to operate in a higher 25-kV range, thermal line losses will be reduced, but a vigilant tree trimming program will be required to reduce the potential for ground fault by contact with vegetation. Reliability data can help an engineer make these types of decisions by revealing potential areas of improvement. Operations personnel are also challenged to address the negative influence of weather-related variables like ice, wind, and heat.

Power quality is another important aspect of reliability. Power quality is typically described in terms of voltage flicker, transient sag and swell, or harmonic duration of currents. Delivery of high-quality, flicker-free power is especially important to many large industrial loads. A momentary interruption can cause industrial equipment to trip off, leading to costly production losses. To improve the power quality and reliability for industrial customers, a utility may track its voltage transients and employ transient voltage surge suppression, VAR support, or other remediation.

## Reliability Statistics and Their Uses

Reliability statistics are the quantitative basis for good decision-making and come in many forms. Overall, reliability statistics are excellent for self-evaluation. That's not to say utility-to-utility comparisons cannot be made, but differences specific to each electrical network, such as weather conditions, number of customers served, customer willingness to pay for reliability, and equipment used, limit the value of such comparisons. Some regulators take the perspective that standardized metrics are paramount for cross-utility comparison. While such comparisons have benchmarking value, the metrics are most useful when examined from period-to-period (week, month, or year) for a single electric system. The data can help each utility make the best decision possible within its specific circumstances.

1 Atsushi Tero, Et al. Rules for Biologically Inspired Adaptive Network Design, Science, Jan 2010

## Starting Points for Reliability

When evaluating utility reliability, a good place to start is with the industry standard metrics found in the IEEE 1366 guide. These metrics were designed by utility personnel to be an integral part of the framework for internal reliability benchmarking and external utility comparison. To benchmark internally or externally, utilities should collect and evaluate at least five years of statistics. After review of the IEEE 1366 document and its metrics, a utility may find that not all the calculations it recommends will help in making better decisions. Where this occurs, it is important for a utility's employees to decide which metrics would be best for its particular circumstances.

The IEEE 1366 guide was developed to help create a general, uniform, and understandable set of metrics for measuring electric distribution system service reliability. IEEE standards are tools to help guide decision making. They are developed as consensus documents by the IEEE societies and approved by the American National Standards Institute (ANSI). Due to the disagreement over the best ways for utilities to track and report reliability data, it took many years of debate before the first 1366 standard was released in 1998. The most current standard was released in 2012. It is important to note that the 1366 standard is not a design standard. In addition, the standard acknowledges that some utilities may not possess the tools necessary to calculate some of the indices.

Calculating reliability metrics is a part of the pathway to continued exceptional performance. To help small utilities with reliability metrics, APPA provides the eReliability Tracker service. In addition, APPA's Demonstration of Energy and Efficiency Developments (DEED) research and development program offers members the opportunity to apply for research-related grants, which could help utilities of all sizes in their efforts to advance public power technologies in all areas, including reliability. Lastly, APPA's Reliable Public Power Provider (RP3) program recognizes utilities with superior performance, including in reliability. The number of utilities applying to this program shows utility interest in tracking and establishing reliability indicators based on sound metrics.

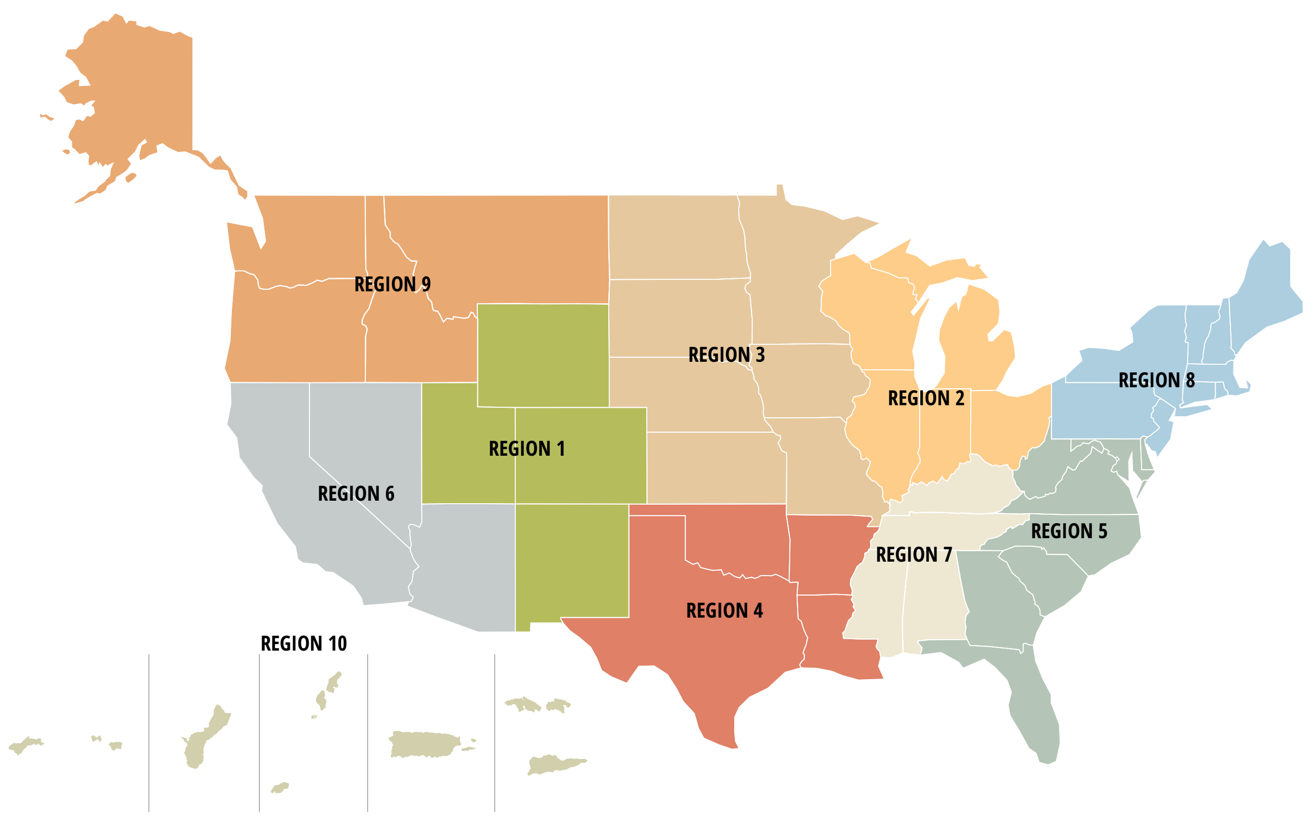
# SURVEY RESPONSES

The data presented in this report are based on APPA's 2020 Distribution System Reliability and Operations Survey. The data reflect activity from January 1, 2020 to December 31, 2020 at 102 responding utilities. Any additional data presented are limited to specific reliability indices collected in the previous biennial surveys. Many respondents did not answer all of the survey questions. Many questions were multiple choice, and, in many cases, a utility could select more than one option. In such an instance, the count of total responses can be greater than the number of total survey participants. However, the count of responses to one option within the question cannot be greater than the total number of survey participants. For example, in a question where participants can check all that apply, the total count of responses can be greater than 102. If the question only enabled the respondent to select one option, then the total number of responses cannot be greater than 102.

The adverse part of conducting a survey with voluntary participation is the possibility of reporting bias. Though APPA feels that the participating utilities are reporting the data with honest intentions, there is always the possibility of non-intentional skewing of the overall data set. Beyond reporting bias, there are regional dissimilarities. For instance, extreme weather is a regionalized and localized phenomenon. Areas that were hit with severe floods or storms during the survey year will typically report comparatively worse reliability. This will be especially true for utilities that do not exclude major event days. As with opposing reporting biases, the possibility of varied national weather can provide some balance.

In total, 102 utilities from nine regions participated in the 2020 reliability survey. Figure 1 shows the different regions. Figure 2 shows that the highest concentration of participants is from regions three and five.

**Figure 1: Regions**



### Figure 1: Regions

Region 1: Colorado, New Mexico, Utah, Wyoming

Region 2: Illinois, Indiana, Michigan, Ohio, Wisconsin

Region 3: Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota

Region 4: Arkansas, Louisiana, Oklahoma, Texas

Region 5: Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia

Region 6: Arizona, California, Nevada

Region 7: Alabama, Kentucky, Mississippi, Tennessee

Region 8: Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

Region 9: Alaska, Idaho, Montana, Oregon, Washington

Region 10: American Samoa, Guam, Northern Mariana Islands, Puerto Rico, U.S. Virgin Islands

### Figure 2: Survey participants by region

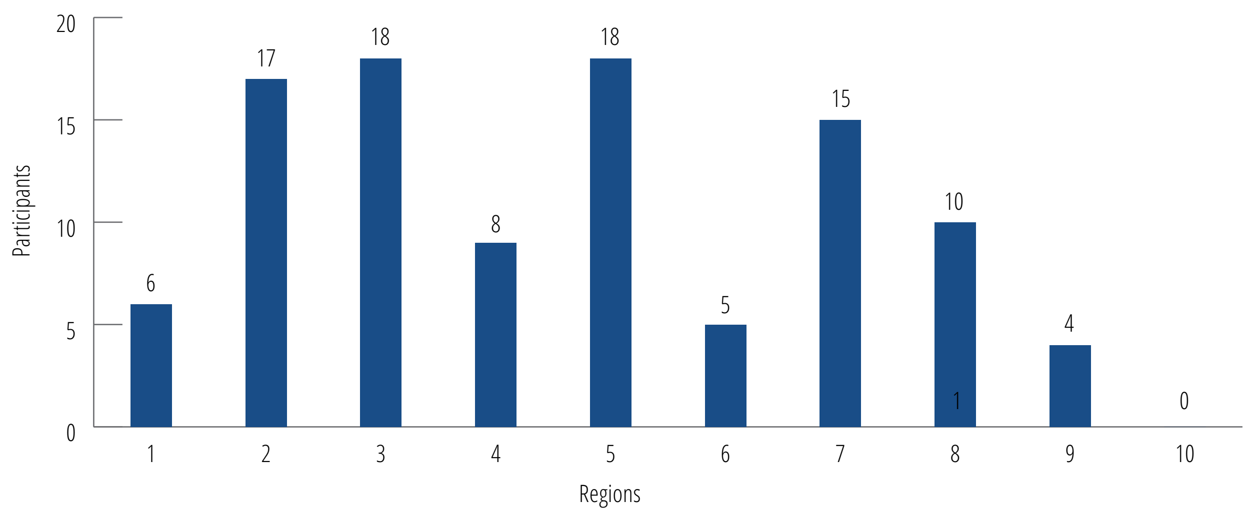
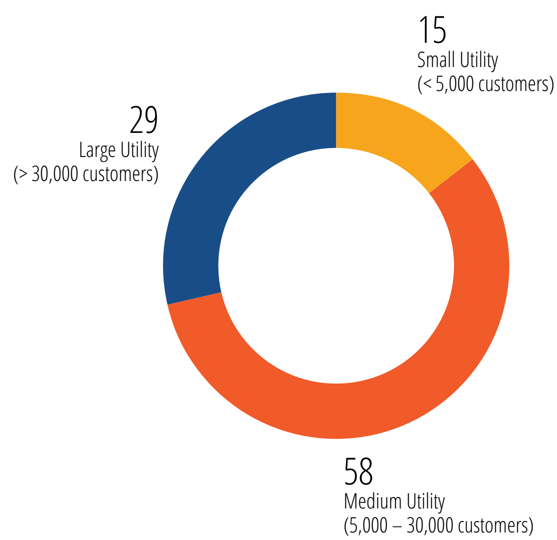



Figure 3 shows the number of customers for each utility that participated in the survey in order of decreasing number of customers served, with most of the respondents serving less than 20,000 customers.

### Figure 3: Utility respondents by total customers served



## SECTION I

# OUTAGE TRACKING

Electricity service interruptions are costly for both utilities and communities.[2] Equipment failure, extreme weather events, wildlife, and contact with vegetation are some of the most common causes of electric system outages. Tracking helps utilities understand and reduce outages. Yet, to track outages successfully, a utility must classify them. This section looks at utility outage tracking practices, such as technologies used and tracking/recording approaches.

Utilities choose differing methods to track outage data. Some prefer to only collect sustained outages, while others will collect data on both sustained outages and momentary interruptions. In addition to classifying outages based on time, utilities have the decision of where to apply their reliability indices. As shown in figure 4, most utilities choose to calculate indices on a system-wide basis to capture the overall health of the system. Many decide to dig deeper by calculating indices by feeder/circuit, substation, or some other level in the system. Applying indices at multiple levels allows utilities to have a general outlook as well as to home in on the specific areas of the system that may need more attention.

2 Understanding the Cost of Power Interruptions to U.S. Electricity Consumers, Kristina Hamachi LaCommare and Joseph H. Eto, Lawrence Berkeley National Laboratory, 2003

Participants were asked to indicate the technologies they use to track outages. Within a technology category, such as SCADA, there are different levels of data acquisition systems. As shown in Table 1, many SCADA systems can report only on certain key points, leaving a utility to rely on customer call-ins to report outages. All utilities that participated in this survey indicated that they use APPA's eReliability Tracker service.

**Table 1**
**Outage tracking/recording technologies used**

| | |
|---|---|
| eReliability Tracker Software | 102 |
| SCADA System | 79 |
| Outage Management System | 58 |
| Paper Records | 47 |
| Smart Grid/Smart Meters/Advanced Metering Infrastructure | 39 |
| Database | 35 |
| Spreadsheet | 33 |

**Figure 4: System levels where utilities apply reliability indices**

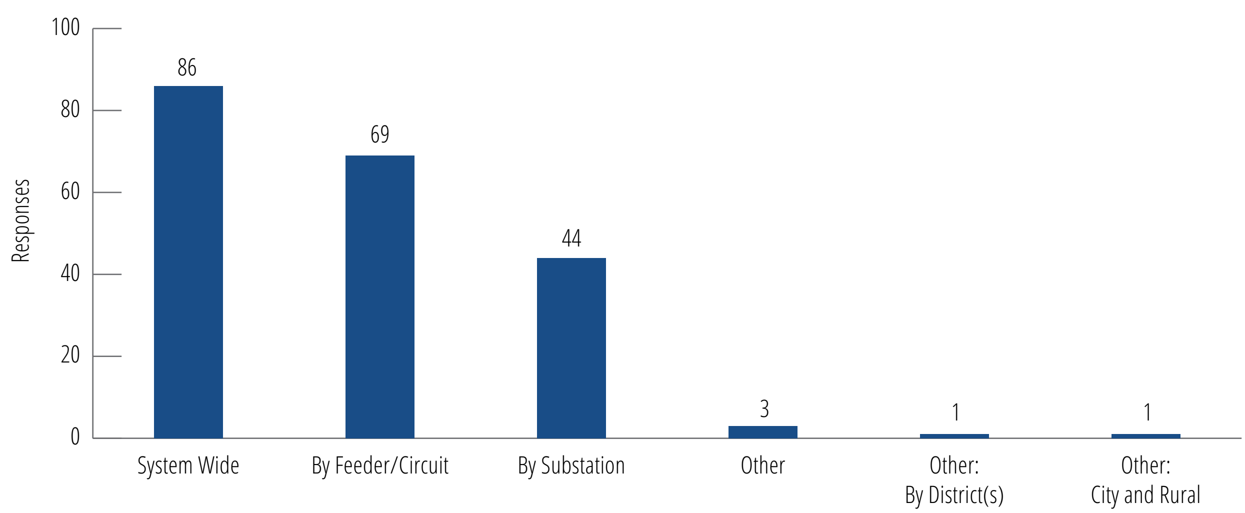


Table 2 shows that a majority of respondents generate reliability reports but most are not required to report them to a commission.

**Table 2**
**Practices for calculating and reporting reliability indices**

| | Yes | No |
|---|---|---|
| Does your utility generate reliability reports? | 95 | 7 |
| Are you required by your state utility commission or public service commission to track/report reliability? | 20 | 81 |

Table 3 shows the average IEEE 1366 reliability statistics calculated using the 2020 outage data from the eReliability Tracker. The statistics include the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Average Service Availability Index (ASAI).

**Table 3**
**Average reliability indices data from the eReliability Tracker, 2020**

| | Average |
|---|---|
| SAIDI (minutes) | 139.16 |
| SAIFI (interruptions) | 0.86 |
| CAIDI (minutes) | 143.52 |
| ASAI (%) | 99.9747 |

Calculating reliability statistics alone is not enough to aid in the improvement of a system. Generating reliability reports allows utilities to do a proper analysis and gain an understanding of any distribution system. All utilities that participate in the eReliability Tracker receive a customized annual reliability report enabling them to benchmark their reliability performance (see a Sample Annual Report). As can be seen in Figure 5, many utilities choose to share these reports internally, publicly through newspaper outlets and articles, or with their board or public utility commission (PUC).

**Figure 5: Methods used to share reliability reports**

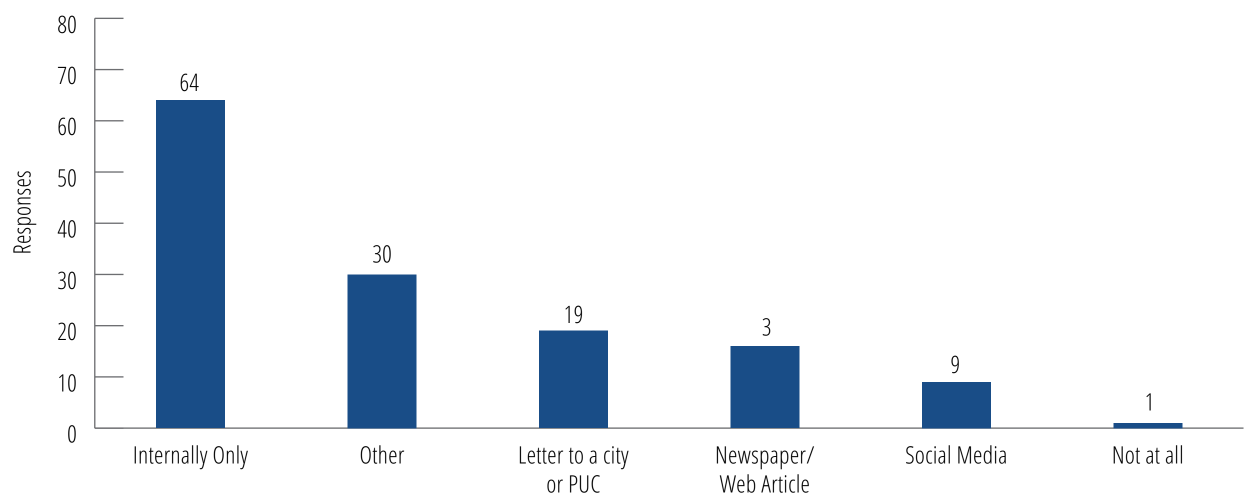
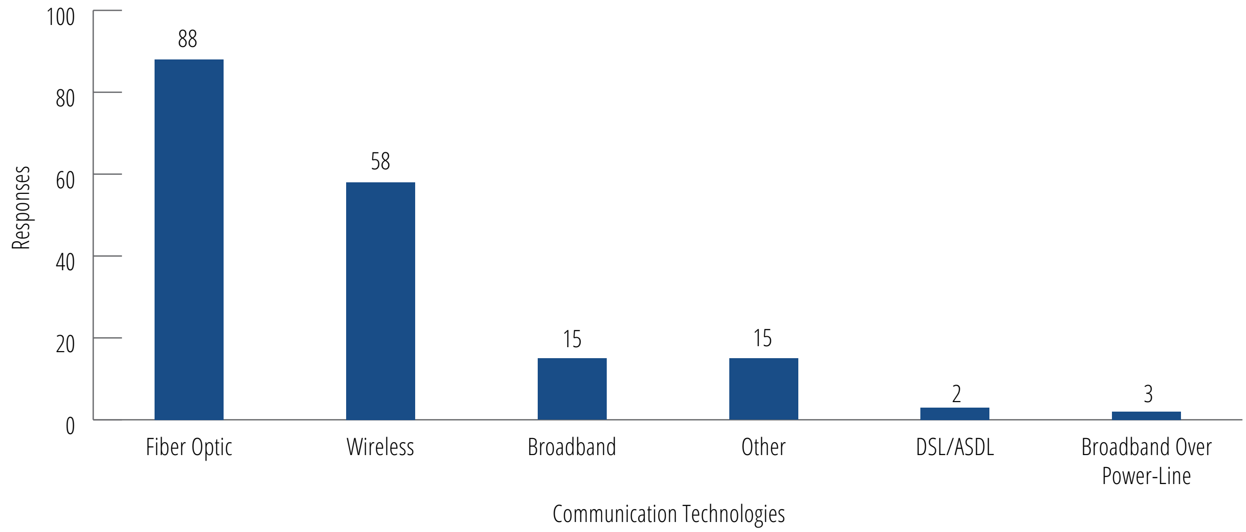



**Table 4**
**Implementation of an automated switching scheme**

| | Yes | No |
|---|---|---|
| Has your utility implemented an automated switching scheme? | 31 | 71 |

**Figure 6: Communication technologies used for retrieving distribution system information**




Due to the growing presence of technology in the industry, it is important for utilities to assess the different available technologies used for retrieving distribution system information. Figure 6 shows which system technologies respondents use.

The survey dove a little deeper for the utilities selecting wireless technologies to illustrate which wireless technologies are used for retrieving distribution system information. Table 5 shows which wireless technologies respondents use. Often these wireless technologies are used in combination with the other technologies shown in Figure 6.

**Table 5**
**Count of utilities using different wireless technologies**

| | |
|---|---|
| Radio-licensed spectrum | 28 |
| Mesh (Wi-Fi) | 18 |
| Cellular (2G, 3G, 4G, LTE, 5G) | 15 |
| Microwave | 6 |
| Satellite | 2 |

SECTION II

# POWER QUALITY

Though seemingly an overarching term, power quality typically describes the quality of a distribution system's voltage and current in terms of its sinusoidal form, constant amplitude, and constant frequency. Accordingly, APPA considers power quality to be an integral part of a utility's service to its customers; however, this report does not address power quality issues on a deep technical level. Rather, this section of the report examines the perceived and factual links between power quality and distribution system reliability.

Many utilities limit the discussion of reliability to outages. However, power quality is a key component of reliability. Many standards address power quality.[3] Moreover, power quality issues vary in scope and addressability. On one hand, a utility can spend significant amounts of money to create a power system with a near-perfect sinusoidal voltage source, regardless of what is happening. On the other hand, a public power utility must pass all of its costs — including power quality control costs — on to the customer. Thus, utilities must find a middle ground that can accommodate customers' power quality needs, allow for addition of unexpected new load without significant impacts, and keep costs at a reasonable level.

Increasing use of sensitive electronic equipment is creating more loads that respond to distribution system power quality indicators. This problem is compounded by the non-linear nature of many loads. Voltage sag and swell and harmonic currents can be created by distributed generation, load switching or operating many high load devices.

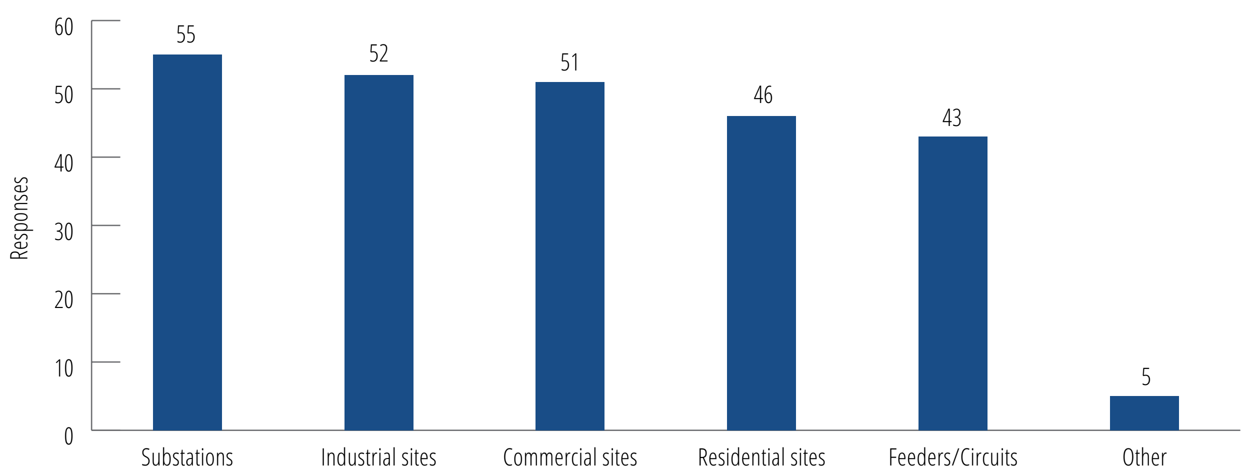
There is a link between the overall power quality a customer experiences and the power usage of other customers nearby. For example, a customer switching on high-wattage motors, arc-welders, or HVAC equipment can create voltage sags for other customers.[4]

For certain customers, power quality monitoring services can be valuable. As shown in Figure 7, public power utilities perform power quality monitoring at various sites.

3 See IEEE Std. 142, 519, 1159, 1250 and 1346

4 Power quality primer By Barry W. Kennedy, 2000

**Figure 7: Power quality monitoring by location**



In an electric distribution system, customer actions can impact the quality of system operation. For example, the operation of an industrial device that draws a large amount of current with significant cycle variations, such as an arc furnace, can cause rapid fluctuations in local system voltage. The visual effect of these fluctuations is commonly referred to as flicker. As a power quality problem, flicker can be seen visibly in most lighting applications, including incandescent and LED lights, and can be irritating to consumers.

To address flicker, some utilities have flicker standards. Table 6 depicts respondents concerns with certain voltage-related power quality problems. Utility respondents could select multiple problems that are concerns.

**Table 6**
**Concerns with power quality problem related to voltage**

| | |
|---|---|
| Voltage Sag | 72 |
| Voltage Swell | 42 |
| Transient Spike | 39 |
| Flicker | 32 |
| Total Harmonic Distributions (THD) | 22 |
| Frequency Variation | 9 |
| Noise | 7 |
| Other | 1 |

Power quality issues can take many forms. A utility may find itself in the position of mediator between a customer causing power quality problems and other nearby customers experiencing the problems. In these cases, it is not unusual for a utility to ask customers to take steps to curb power quality impacts to the electric system. Consequently, exposed customers may be asked to take steps to isolate sensitive equipment. Regardless of the power quality problem, having a policy or requirement to take action to resolve the issue is important.

With the growing demand for renewables and distributed energy resources (DERs), utilities were asked if they have had any challenges integrating these technologies. As shown in Table 7, most utilities have not experienced any issues. The utilities that did stated the challenges were with collecting accurate interruption data and high voltage conditions with solar facilities.

**Table 7**
**Utilities experiencing power quality challenges with renewables and DERs**

| | Yes | No |
|---|---|---|
| Has your utility experienced any power quality challenges when integrating renewables or distributed generation sources in the last three years? | 6 | 96 |

SECTION III

# OUTAGE PREVENTION AND RESTORATION

Many utilities have outage prevention programs as a part of their operations plan. This section looks at utility outage prevention plans and utility participation in mutual aid and disaster planning.

Regular inspection, maintenance, and outage-prevention programs can provide valuable reliability-related data. Among programs identified by respondents, tree trimming, as a subset of vegetation management, was most frequently selected to help reduce outages. It can be helpful to use system reliability statistics to identify where tree trimming is needed, such as by evaluating the data to reveal a utility's worst performing circuits.[5]

**Table 8**
**Outage prevention practices**

| | |
|---|---|
| Vegetation management/Tree trimming | 88 |
| Animal/Squirrel guards | 86 |
| Routine distribution inspection and maintenance | 81 |
| Thermographic circuit inspections | 67 |
| Lightning arresters | 60 |
| Review of worst performing circuit | 57 |
| Converted overhead to underground | 52 |
| Transformer load management | 43 |
| Covered wire | 41 |
| Root cause analysis | 35 |
| Circuit rider program | 21 |
| Other | 12 |

Trees, while beloved by most customers, are ever-growing hazards for electric lines. When a tree or other vegetation makes contact with a line, depending on the line's voltage and shielding, a path to ground may be created and an outage can occur. When vegetation crosses two lines, a phase-to-phase fault can occur, and may not be immediate. The conductive path between two wires can be created over time as the current from the wires drives out a small inner section of the branch making contact between the wires.[6] If a branch crossing between two wires is sufficiently desiccated, a fault can be created through the plant material. There are many ways to trim trees without removing the entire plant. Methods include topping, side trimming, and through trimming.

The downside of a trimming program is that it is a continuous process. It is important to select a routine that ensures that in between trims, if a storm occurs, branches remain within a proper distance from the lines. Figure 8 shows that 43% of survey respondents who provide tree trimming programs continuously trim trees.

Approximately 74% of utilities' tree trimming policy or practice is not restricted to their local regulations. These results reflect public power's proactive engagement in tree trimming practices to effectively prevent outages caused by trees. Figure 9 shows the distribution of total annual tree-trimming cost, in dollars, to the utilities. Most utilities spend less than $2 million on tree trimming programs/practices per year.

5 State of New York Department of Public Service, In the Matter of the Review of Long Island Power Authority's Preparedness and Response to Hurricane Irene, Case 12-E-0283, 2012

6 Electric Power Distribution Reliability, Richard E. Brown, 2009

**Figure 8: Frequency of tree-trimming practices**

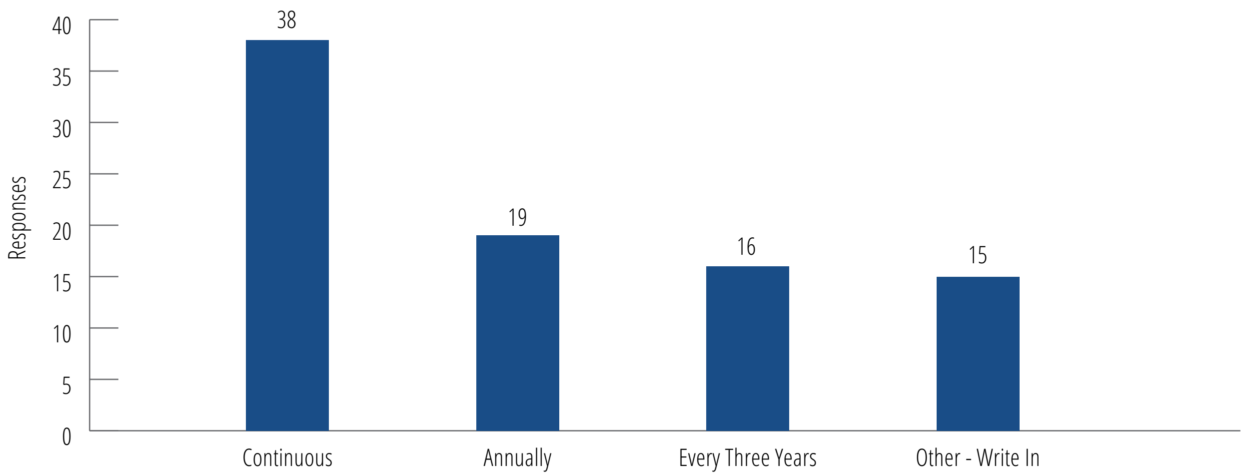
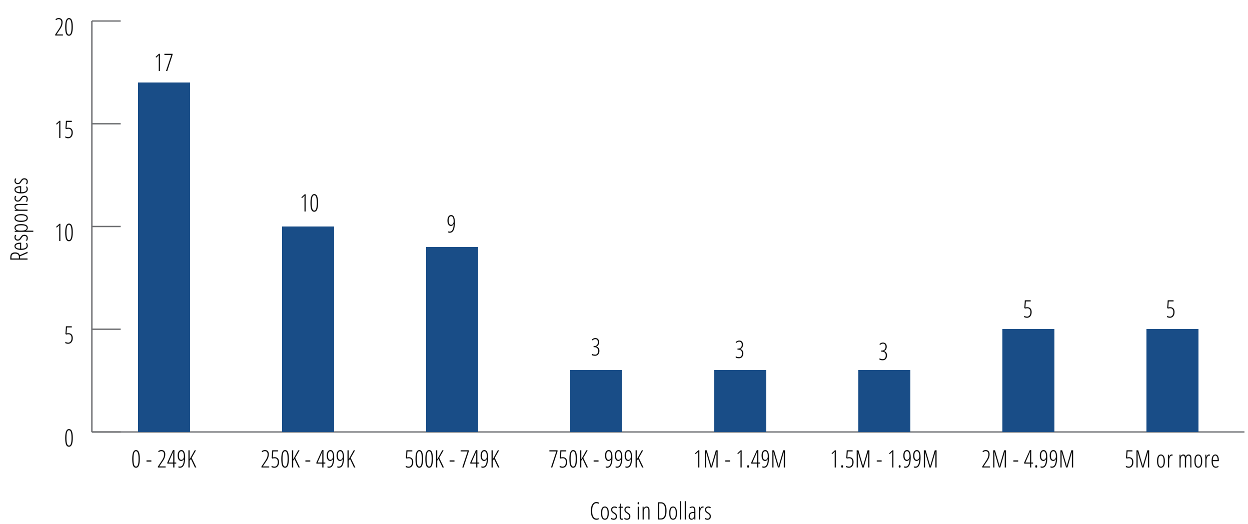



**Figure 9: Annual tree trimming cost**




Other popular outage prevention programs are animal guards and lightning arrestors. Shield wires and lightning arrestors provide protection for circuits that are susceptible to lightning strikes. In many regions, wildlife-related outages are due to squirrels. Since a utility pole is similar to a tree, squirrels frequently climb poles. The heat emitted by electric lines can attract a squirrel, particularly during cold weather. Nearly all squirrel activities that cause outages on distribution transformers can be mitigated by using squirrel guards.

Outside of regular outage management plans comes the management of major events and catastrophes. Approximately 94% of the total survey respondents have major storm, event, or disaster plans, and of these plans, about 90% are written or documented.

SECTION IV

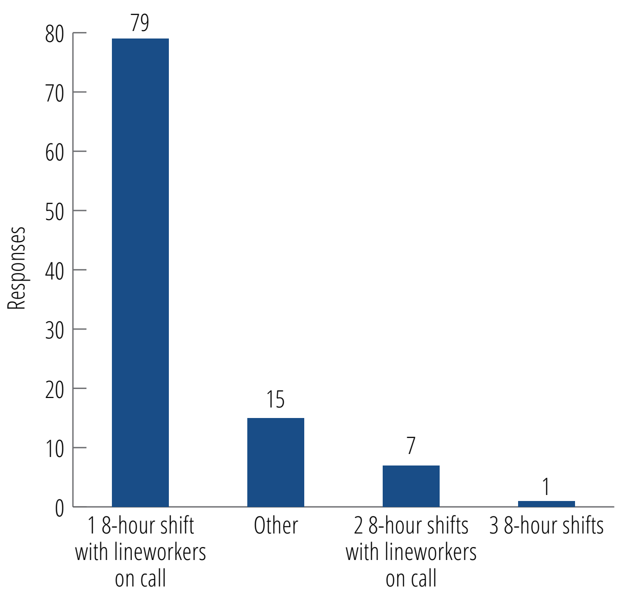
# WORKFORCE

A workforce that can maintain the distribution system is an essential part of any utility's operations. Of that workforce, lineworkers are the primary staff charged with the maintenance and upkeep of the distribution system. This section looks at methods of providing crew coverage and the average rates of lineworkers by customer count and territory size.

Since there is 24-hour demand for electricity, it is important that a utility find a way to make lineworkers available at all times to solve any delivery problems that arise. In the survey, participants were asked how their utility provided 24-hour crew coverage.

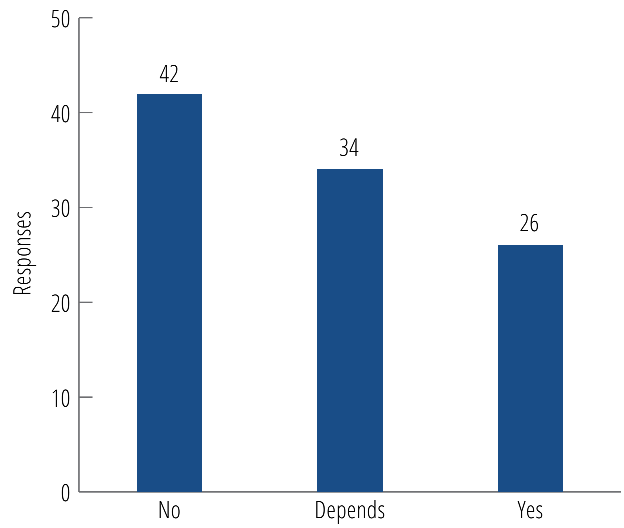
As shown in Figure 10, the majority of utilities report using one eight-hour shift with on-call lineworkers.

**Figure 10: Method for providing 24-hour crew coverage**



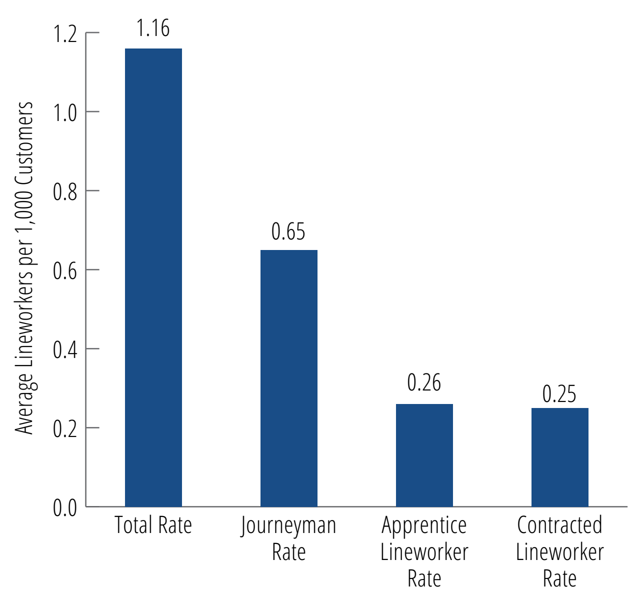

In the survey, the average number of crews that each utility employs was broken down into the categories of apprentice, journeyman, mixed and contract. There was significant variety in the number of lineworkers each utility employs. Figure 12 shows the average customer-weighted rate for employing the three different categories of lineworkers. The rates represent the number of lineworkers of that category per 1,000 customers. For

**Figure 11: Respondents that allow employees to take vehicles home**



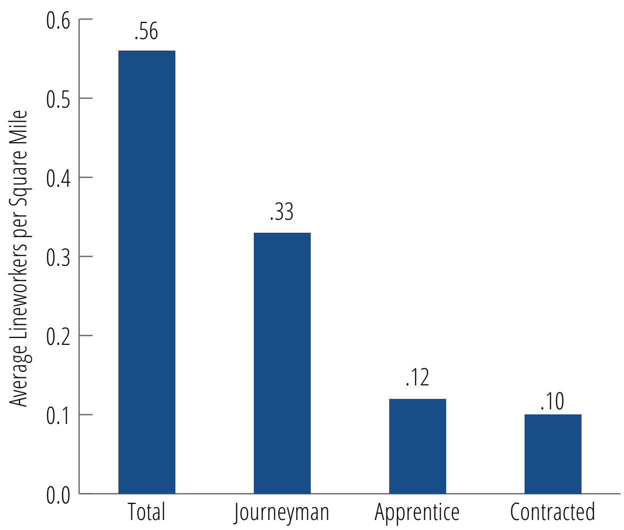

example, a "1" in the journeyman column means that on average one journeyman is employed at the utility per 1,000 customers.

**Figure 12: Average customer-weighted rates for employing types of lineworkers**



Interestingly, the data showed a wide range of lineworkers per square mile. This range might be useful for a utility in determining the number of lineworkers a utility should employ to cover a service territory. Since each utility is different both in condition and circumstance, significant deviation from this range does not necessarily warrant concern.

**Figure 13: Average rate of lineworkers per square mile**



SECTION V

# SYSTEM OPERATION

In a typical distribution system, the substation is the delivery point for power. As a result, maintaining and operating the substation transformers is important to the reliability of the power system. Every time a transformer is overloaded, its useful life is decreased. Typically, this happens through the long-term degradation of the insulating medium.[7] This section looks at specific system characteristics, such as types of materials used, transformer maintenance practices, and fault indication methods.

As utility personnel know, substations are important nodes in the electrical system. As central nodes, substations are of high concern to the overall reliability of the electric system. Circuit breakers protect transformers and ensure a problem on one circuit does not transfer to the transformer and other circuits. The circuit breaker is typically the last line of protection between a circuit and a transformer. It can be designed and built as part of a transformer protection scheme at many levels of technological complexity. The types of breakers used in these ways have stayed consistent since the last survey was done with 2017 data.

The survey asked about transformer maintenance practices. Table 9 shows the breakdown of questions and responses on maintaining and testing transformers.

**Table 9**
**Transformer maintenance, testing, and buying practices**

| | Yes | No |
|---|---|---|
| Do you have transformer overload guides? | 65 | 36 |
| Do you have an established transformer maintenance program? | 72 | 29 |
| Do you test transformer oil? | 96 | 3 |
| Does your utility calculate A and B factors for transformers? | 38 | 57 |
| *If yes, does your utility use the A and B factors as part of the transformer buying process?* | 38 | 0 |
| Does your utility use amorphous core transformers? | 25 | 72 |

7 Investigations of Temperature Effects on the Dielectric Response Measurements of Transformer Oil-Paper Insulation System, IEEE Transactions on Power Delivery, VOL 23, NO. 1, 2008

8 Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems, Schweitzer Engineering, 2010

**Figure 14: Types of breakers used in utility substations**

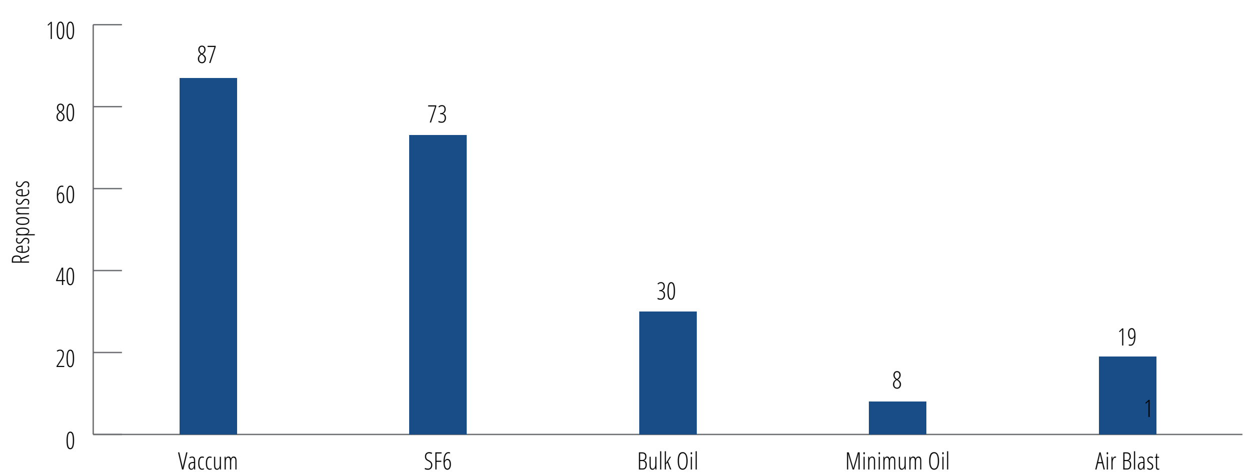


Table 10 contains average customer-weighted rates for distribution system components for every 1,000 customers served. These rates are customer-weighted to limit differences in utility size. For example, a "1" indicating rate of distribution substations in operation means the average or median utility has one distribution substation in operation for every 1,000 customers.

**Table 10**
**Average, median, and standard deviation of rates for distribution system components and characteristics per 1,000 customers**

| | Average | Median | Standard Deviation |
|---|---|---|---|
| Rate of distribution substations currently in operation | 0.58 | 0.41 | 0.57 |
| Rate of total distribution substation transformers currently in operation | 0.87 | 0.64 | 0.84 |
| Rate of total substation transformer capacity in MVA (Oil Air) | 11.32 | 10.12 | 7.90 |
| Rate of total installed distribution (field) transformer capacity (MVA) | 11.83 | 12.26 | 10.99 |

Figure 15 shows the various types of material composition respondents use. Aluminum is the material most commonly used for primary feeder cables.

The survey also asked utilities about the voltages they operate on their distribution system. This data can help utilities understand the decisions other utilities are making about distribution system voltage.

To protect lines, equipment, and customers against damage from electrical faults, utilities employ fuses, reclosers, switches, sectionalizers, relays, and circuit breakers. A relay is commonly the first element to react to some type of electrical abnormality in a distribution line. Relays are the "brain" of the protection system for distribution components. Relays are often located in substations to monitor and take action upon the detection of various power conditions on feeder lines. Due to the emergence of cost-effective and reliable monitoring electronics, power quality-based distribution protection functions are being integrated into many protection devices.[8] Accordingly, many relays have their reaction to power conditions "timed" to save or blow fuses. Fuse forcing generally implies that fuses are set to blow prior to switch or breaker operation.

**Table 11**
**Operating voltages, overhead and underground**

| Voltage | Overhead | Underground |
|---|---|---|
| 4160Y/2400 | 19 | 16 |
| 6900 | 1 | 1 |
| 8320Y/4800 | 1 | 2 |
| 12000Y/6930 | 4 | 4 |
| 12470Y/7200 | 51 | 50 |
| 13200Y/7620 | 16 | 16 |
| 13800Y/7970 | 26 | 25 |
| 20780Y/12000 | 2 | 2 |
| 22860Y/13200 | 3 | 3 |
| 23000 | 1 | 1 |
| 24940Y/14400 | 9 | 9 |
| 34500Y/19920 | 10 | 7 |
| Other | 4 | 3 |

8 Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems, Schweitzer Engineering, 2010

**Figure 15: Material for primary feeder cables**

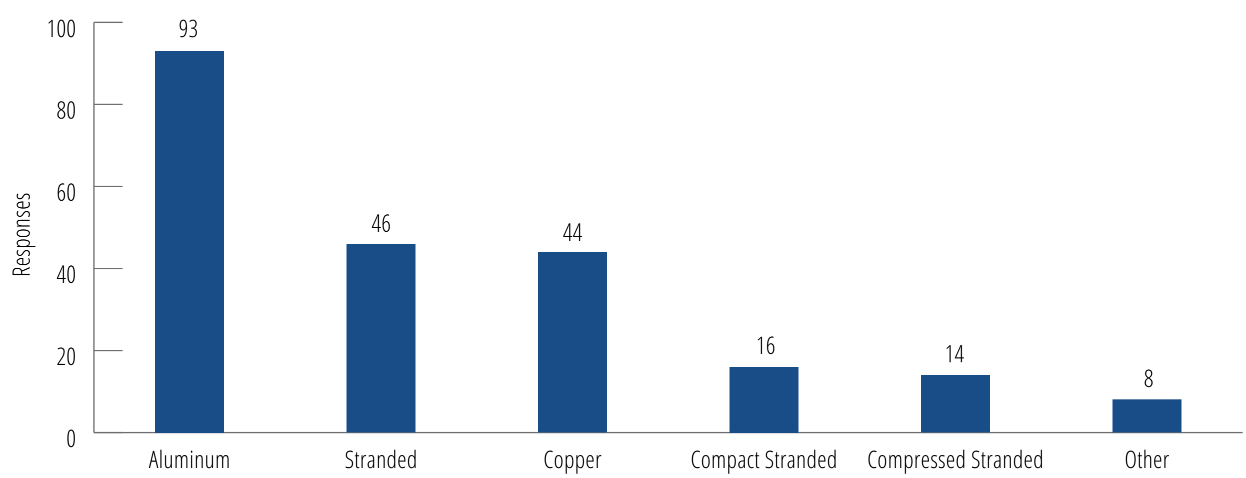


**Table 12**
**Distribution system fuse philosophy**

| | |
|---|---|
| Fuse Force (i.e., fuse blown prior to breaker operation) | 76 |
| Fuse Save (i.e., instantaneous trip first, then blow fuse) | 26 |

Figure 16 shows that a thumper is the most popular method to locate faults. Figure 17 shows that the majority of utilities use a section-by-section method to sectionalize faulted sections.

**Figure 16: Fault location method**

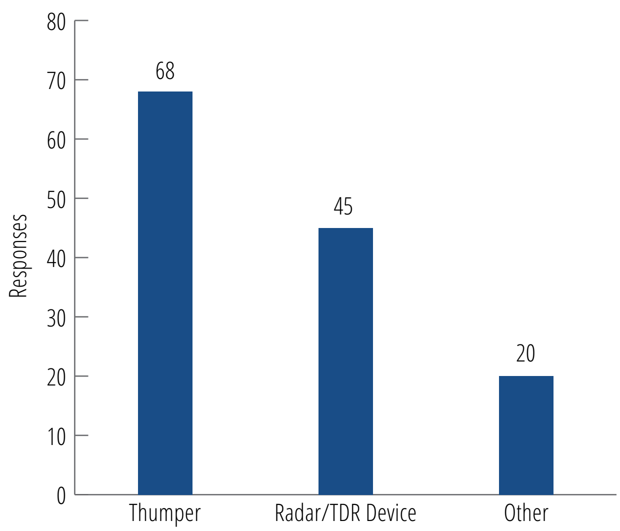
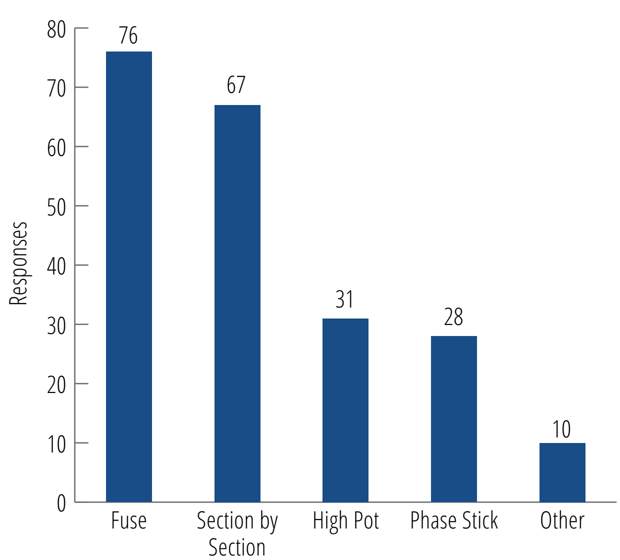
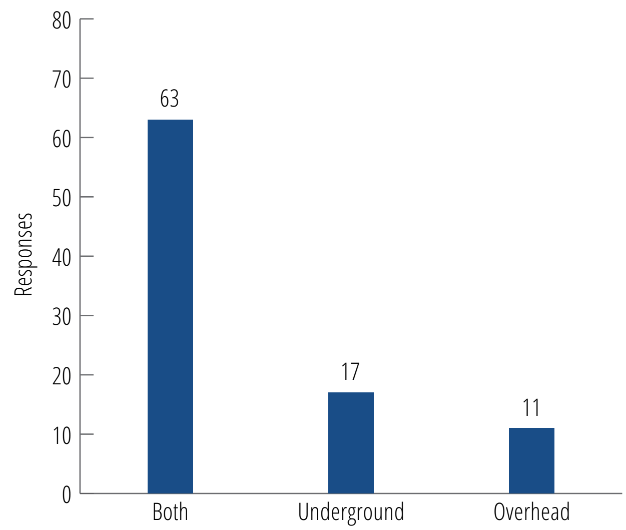



**Figure 17: Method to sectionalize faulted sections of cable**




Fault indicators are used in electric distribution networks to identify and, in some cases, signal or communicate faulted circuits. Both overhead and underground fault indicators are commonly used. Figure 18 shows the number of respondents using fault indicators on their overhead system, underground system, or both. Figure 19 shows the common types of fault signals used.

**Figure 18: Use of fault indicators on electrical systems that are overhead, underground, or both**



#### Figure 19: Types of fault signals used

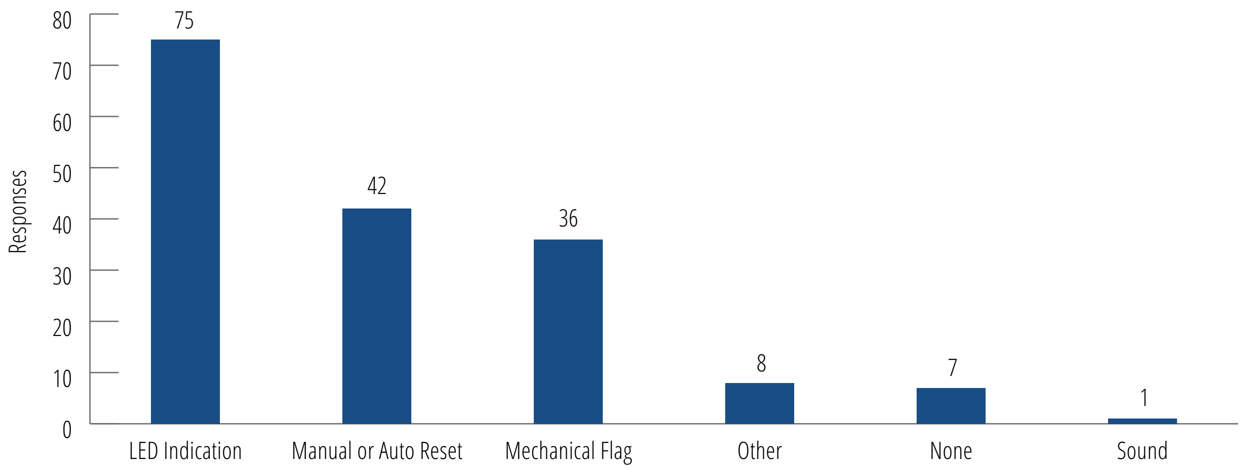
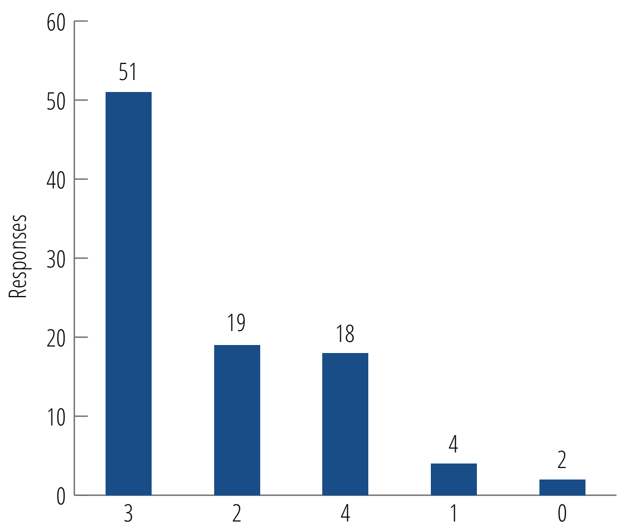



Figure 20 suggests that it is most common to allow three relay recloses before lockout. This assumes that respondents have automatic reclosers, though respondents were not asked directly in the survey. This strategy may provide more closing cycles to clear a fault or allow other switching devices on feeder lines to operate. The downside of this strategy would be the repeated short-term interruption of any customers with sensitive power quality needs on a particular line.

#### Figure 20: Relay recloses to lockout




As shown in Table 13, after the first close, many utilities choose to increase the time a relay stays open. Relay practice widely varies between utilities; however, the close time for a relay after it has been opened is often based on the time-current curve used by the utility. Some utilities have a close timing specification set differently from the time-current curve. Figure 21 and Figure 22 illustrate the frequency of responses for the average duration prior to recloses. Both graphs show that most utilities answered around 10 seconds prior to the second reclose.

#### Table 13
#### Average duration prior to reclose (in seconds)

| | Commercial /Industrial Feeder/Circuit | Residential Feeder/Circuit |
|---|---|---|
| 1st | 4.81 | 3.16 |
| 2nd | 19.12 | 23.95 |
| 3rd | 18.59 | 55.21 |
| 4th | 23.42 | 25.08 |

**Figure 21: Average duration prior to reclose, commercial/industrial feeder/circuits (in seconds)**

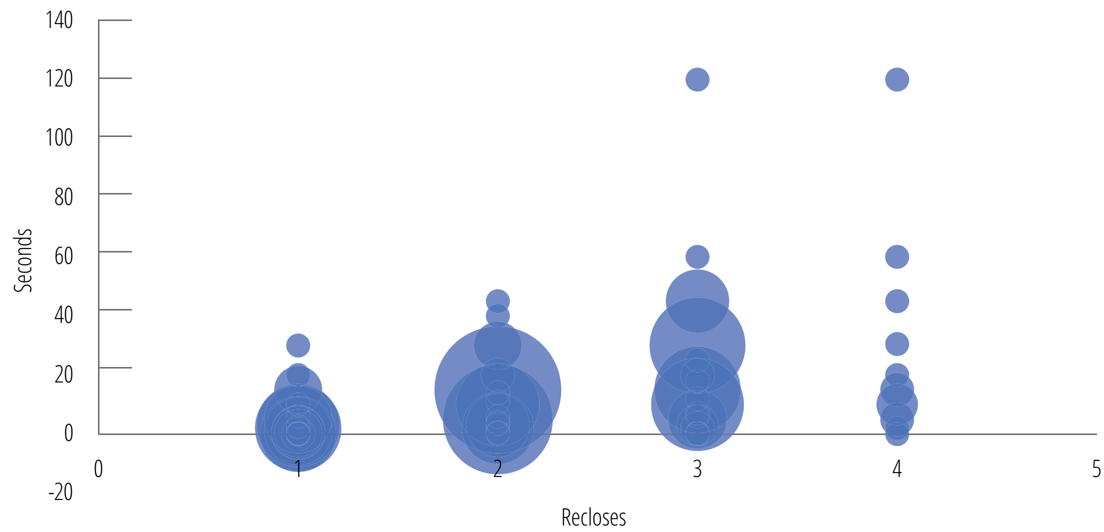
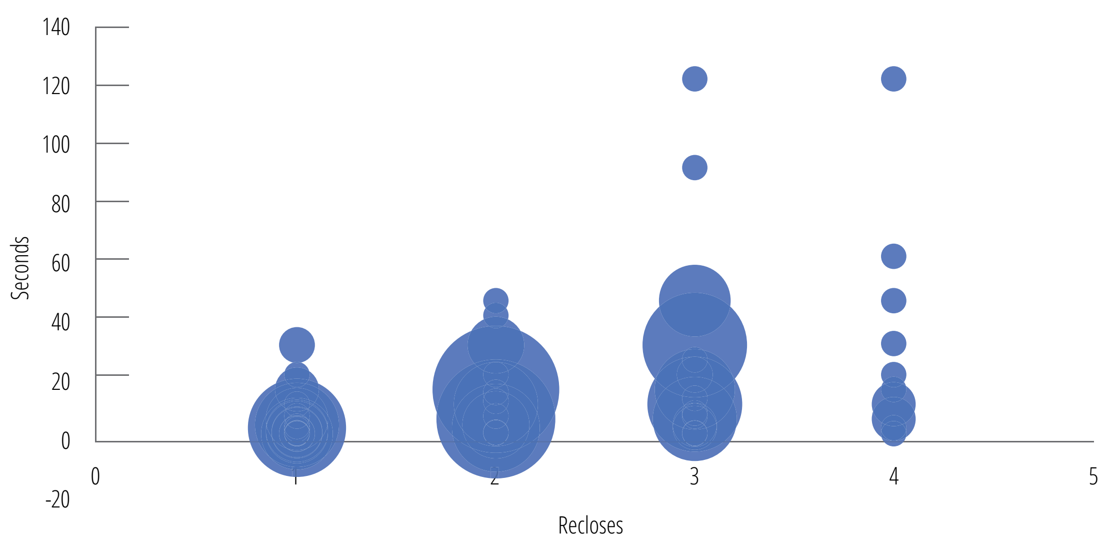



**Figure 22: Average duration prior to reclose, residential feeder/circuits (in seconds)**



SECTION VI

# CONSTRUCTION DESIGN

This section of the survey was intended to help illustrate how utilities handle easements and codes and serve new construction.

As shown in Figure 23, every utility surveyed had at least the right to construct, maintain, operate, replace, upgrade, or rebuild pole lines or underground cable and appurtenances thereto. However, asking about utility easements or property rights can help utility managers see the different means that utilities are using to construct, maintain, and operate a given section of utility line. The ideal is that a utility has considered all of these provisions in its easement terms for inclusion.

The rights surveyed were as follows:

- Right to construct, maintain, operate, replace, upgrade, or rebuild pole lines or underground cable and appurtenances thereto
- Right of ingress and egress
- Right to trim and remove all trees on or adjacent to the easement strip necessary to maintain proper service
- Right to keep easement strip free of any structure or obstacle which the company deems a hazard to the line
- Right to prohibit excavation within 5 feet of any buried cable, or any change of grade which interferes with the cable
- Right to install overhead or underground necessary wiring for street lighting that is requested and/or required, but no more than 5 feet from any lot time

**Figure 23: Terms included in utility easements**

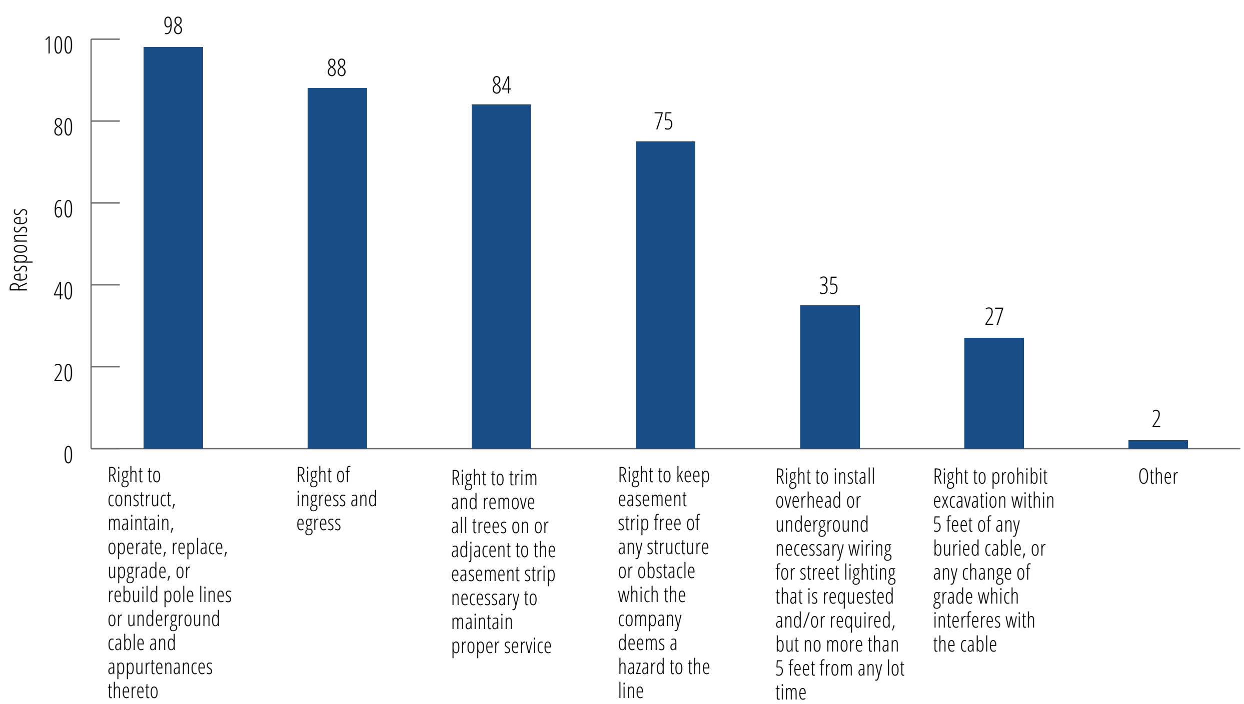


**Figure 24: Utility codes/standards used for construction and installation practices**

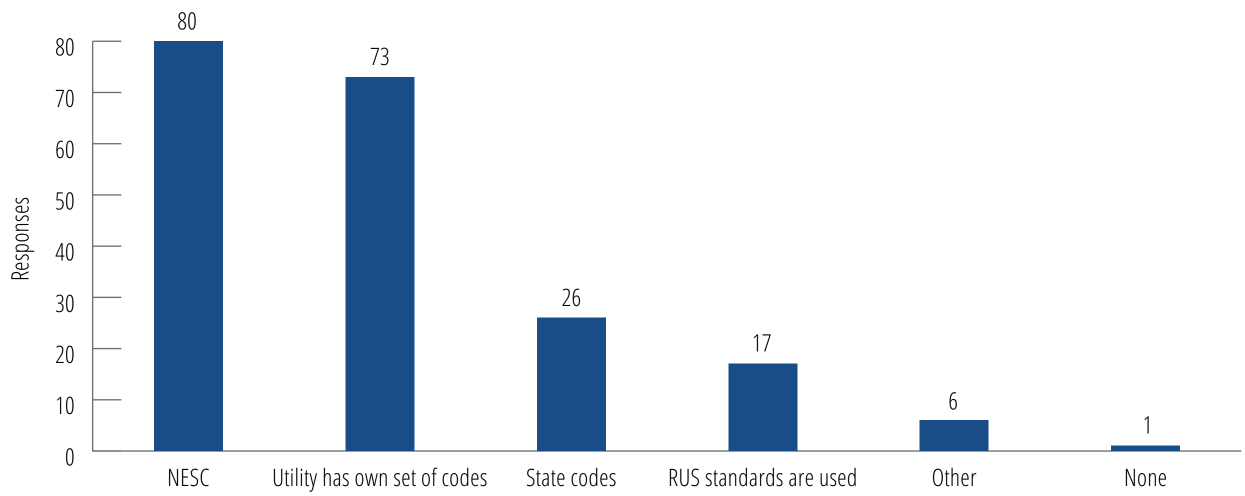
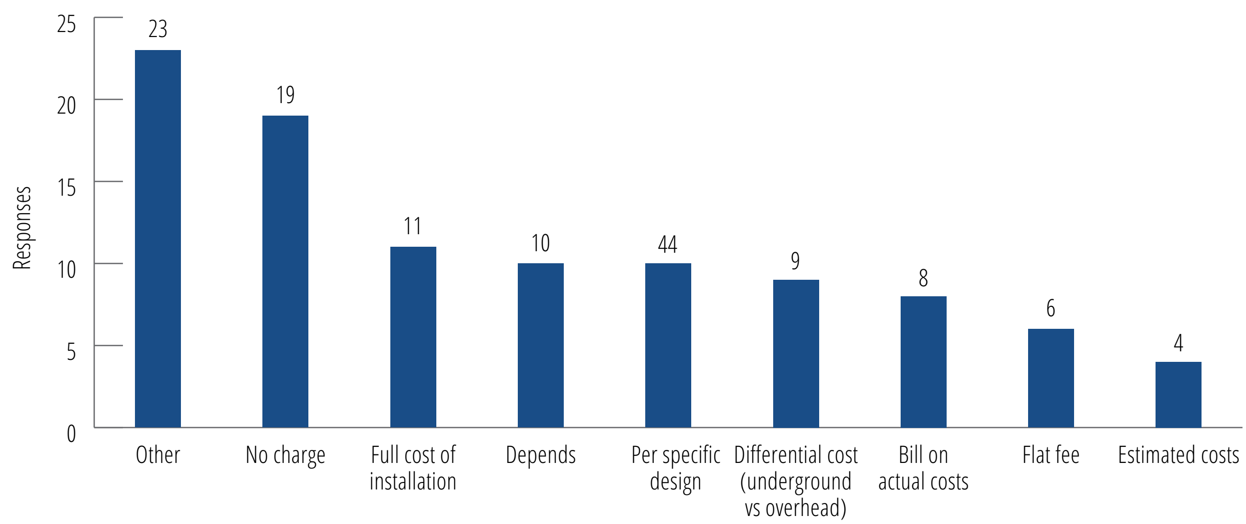



**Figure 25: Charge practice for new construction services to underground subdivisions**

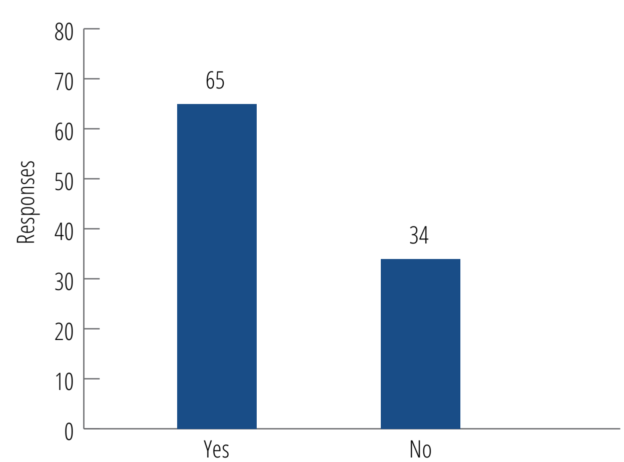



Many utilities use standard codes to guide construction processes. As can be seen in Figure 24, an in-house code for construction and installation practices is the most common, though many utilities also commonly use the National Electrical Safety Code.

Many utilities charge differently for new construction services for underground subdivisions (excluding house services). Figure 25 illustrates the different methods utilities use to recover the cost of new underground subdivision service.

The survey also asked whether a utility charged to convert an existing service from overhead to underground. As can be seen in Figure 26, about two-thirds of respondents charge for this conversion.

**Figure 26: Utility charges to convert from overhead to underground**



Utilities were also surveyed on their new service lateral construction practices. The survey showed on average new house service lateral (low voltage to residence) as 89.85% installed and owned by the utility with 31.15% installed and owned by the customer and 32.23% installed by the customer and owned by the utility.

Figure 27 shows whether a utility allows cable/telephone in the house service trench. Figure 28 shows whether the utilities that did allow cable/telephone in the house service trench charged for the service. The majority of utilities do not charge for in house service trench.

**Figure 27: Utilities that allow cable/telephone in the house service trench**

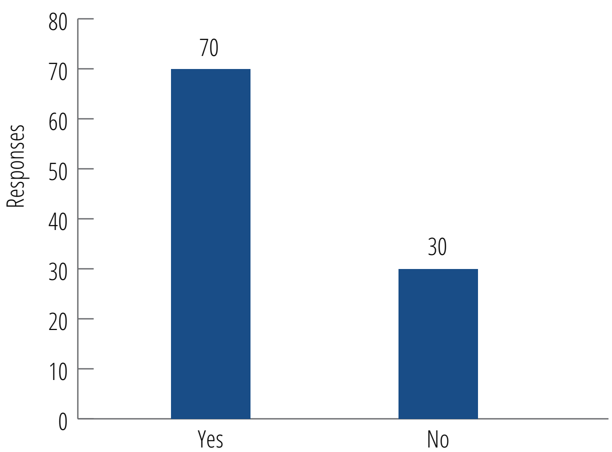
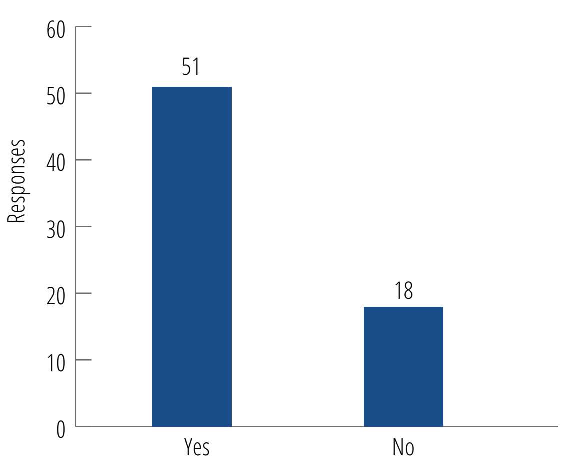
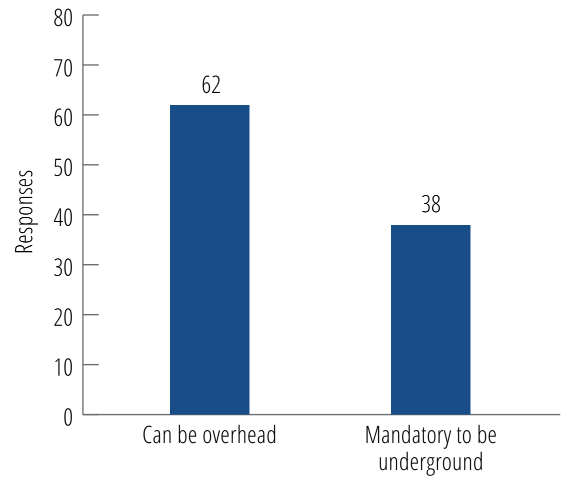



**Figure 28: Utilities that charge for allowing cable/telephone in the house service trench**




Many utilities want to know about mandatory undergrounding. As Figure 29 shows, most utilities said that new construction can be overhead.

**Figure 29: New construction overhead/underground policy**




Some utilities also allow developers to install facilities of a particular type. A utility might allow a developer to install conduit, ground sleeves, or an underground system in its entirety. Figure 30 illustrates whether utilities allow developers to perform work and Figure 31 illustrates what kind of facilities the developer is allowed to install, with conduit and ground sleeves being the most common.

**Figure 30: Utilities allowing developers to install facilities**

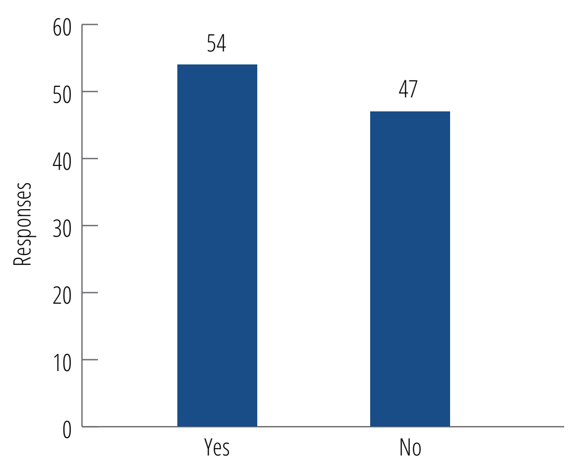
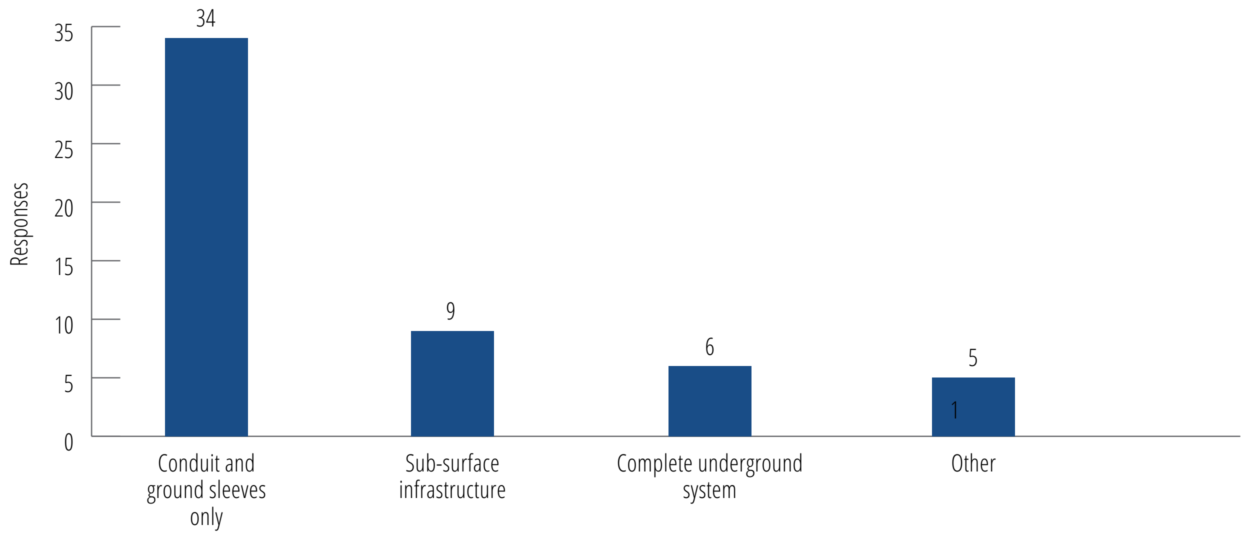


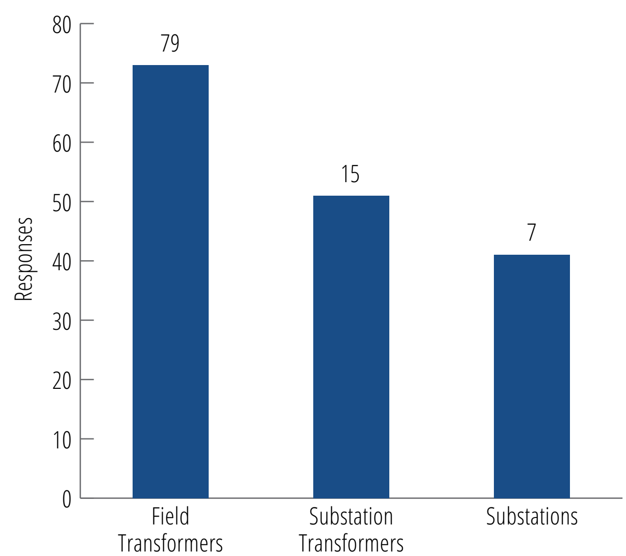
**Figure 31: Type of work utilities allow developers to perform**




Some utilities standardize the sizing of transformers and substations. Figure 32 illustrates that it is most common to standardize the sizing of field transformers.

Many utilities are curious as to how many kVA a typical customer uses. Based on the survey results, for new construction it looks like the average kVA of an installed transformer is 39.22, serving an average of 5.51 customers. The overall survey data shows an average of 6.85 kVA per customer, though the kVA per customer will certainly vary by region and typical house size.

**Figure 32: System elements utilities standardize**



SECTION VII

# GENERAL UTILITY INFORMATION

The general utility information section of the survey was designed to help APPA understand more about the utilities participating in the survey. The utilities that submitted information to this section of the survey gave valuable information for APPA's analysis of relationships between customers, lineworkers, and line mileage. Knowing the general characteristics of the survey participants can give perspective on the applicability of the results to certain utilities.

Since urban and rural were not strictly defined, a utility could use either its own definition or the definition of urban as an overall average density of at least 500 people per square mile. Table 14 shows that the survey participants predominantly serve load in urban areas. Note that the percentages will not add up to 100 since they are averages of the load concentration percentages reported.

Peak load can fluctuate on a daily, monthly, and yearly basis. Figure 33 displays the average peak load reported by region. Region 2 had a slightly higher peak load than the other regions during this period, which is likely due to a higher number of respondents from that region that serve a larger customer base.

**Table 14**
**Average rural and urban concentration per region**

| Region | Urban (%) | Rural (%) |
|---|---|---|
| 1 | 66.38 | 33.62 |
| 2 | 88.94 | 11.06 |
| 3 | 85.26 | 14.74 |
| 4 | 70.63 | 29.38 |
| 5 | 73.11 | 26.83 |
| 6 | 86.84 | 13.16 |
| 7 | 65.83 | 34.17 |
| 8 | 71.25 | 28.75 |
| 9 | 71.67 | 28.33 |

**Table 15**
**Customers served by survey respondents**

| | Average | Median |
|---|---|---|
| Residential | 34,703.36 | 11,091.50 |
| Commercial | 4,785.87 | 1,776.00 |
| Industrial | 176.82 | 21.00 |
| **Total** | **13,222.06** | **13,267.00** |

**Figure 33: Average distribution system peak load, by region (in MW)**

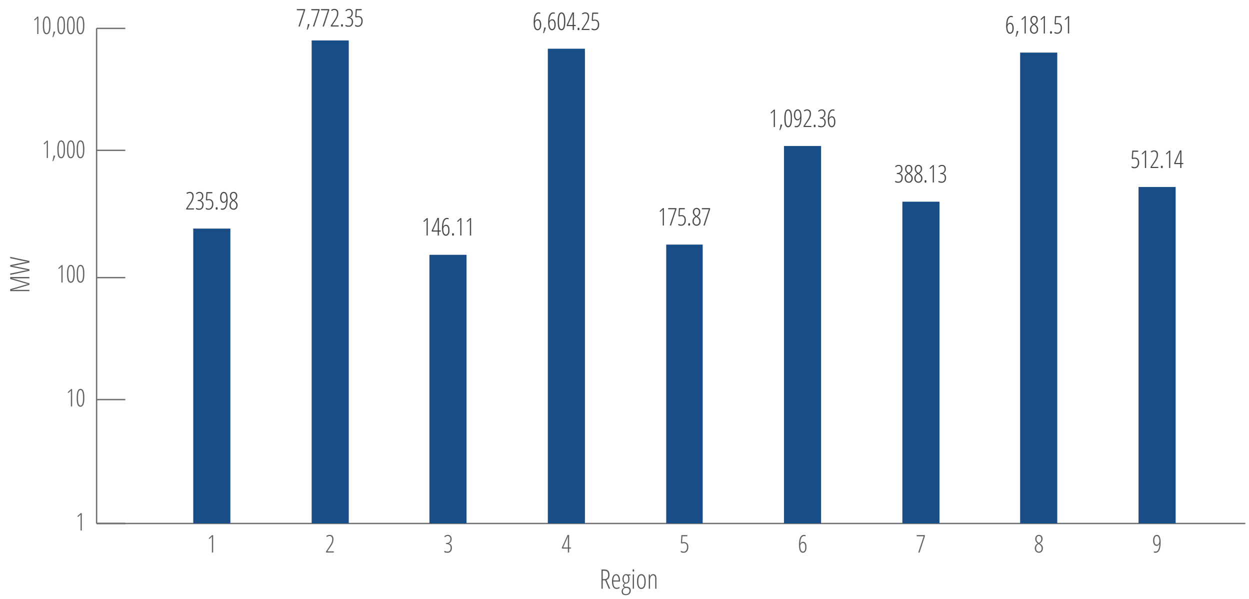
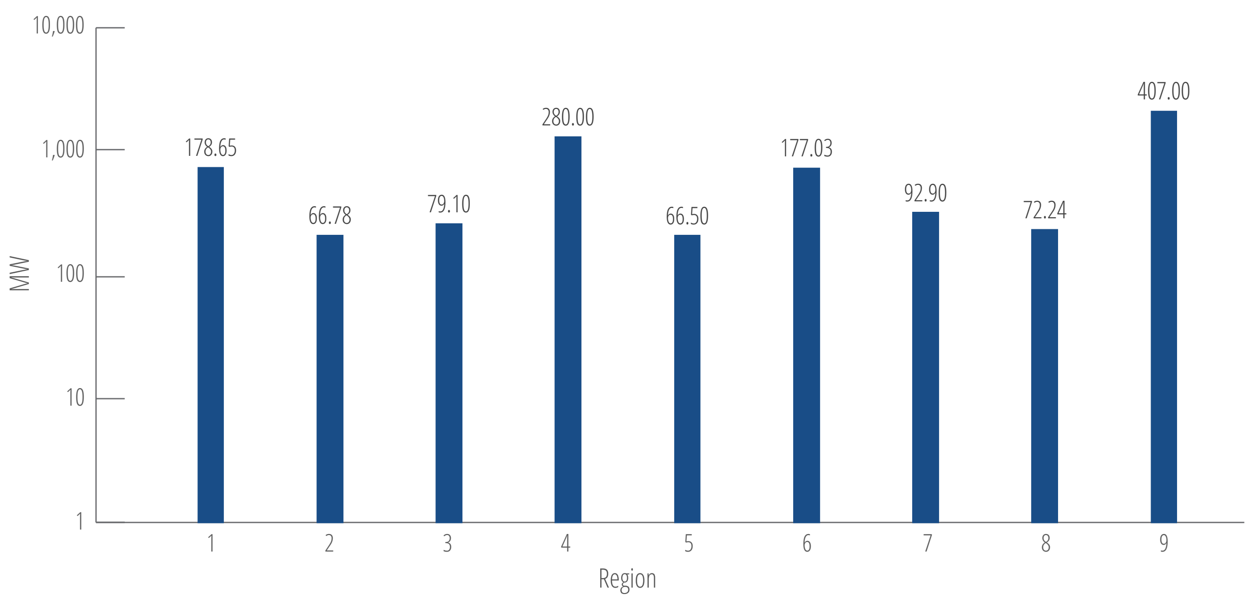



**Figure 34: Median distribution system peak load, by region (in MW)**



# CONCLUSION

Starting or maintaining a program to track and evaluate reliability data is essential. Further, participation in APPA's Distribution System Reliability and Operations Survey is a beneficial exercise for engineers and operations personnel in the public power field. It is only through consistent and thoughtful participation that we will be able to explore in depth the issues that confront us as an industry.

To measure system reliability successfully, utility staff should commit to the long-term uninterrupted collection of reliability related data. Measuring reliability is a deliberate process and takes a significant number of observations before it yields meaningful data. Commitment to measuring system reliability is a best practice and by participating in leading programs such as APPA's Reliable Public Power Provider program and eReliability Tracker, a utility stands to gain significantly.

APPENDIX

# DSR&O SURVEY QUESTIONS

## 2020 DISTRIBUTION SYSTEM RELIABILITY & OPERATIONS SURVEY

All individual data will remain confidential and presented as composite data only.*

First Name of Respondent: ____________________________________________

Last Name of Respondent: ____________________________________________

Title: ____________________________________________

Utility Name: ____________________________________________

State: ____________________________________________

Phone Number: ____________________________________________

E-mail Address: ____________________________________________

**1) Which outage tracking/recording technologies do you use? (check all that apply)**

[ ] Paper Records [ ] Spreadsheet (for analysis and history)

[ ] Database (for analysis and history) [ ] eReliability Tracker software

[ ] Outage Management System (If checked, which brand of OMS): ____________________________________________

[ ] SCADA System (If checked, which brand of SCADA system?): ____________________________________________

[ ] Smart Grid/Smart Meters/Automated Metering Infrastructure

[ ] Other: ____________________________________________

**2) Where on your system does your utility apply reliability indices? (check all that apply)**

[ ] System Wide [ ] By Feeder/Circuit

[ ] By Substation [ ] Other: _________________________

**3) Has your utility implemented an automated switching scheme (distributed automation, etc.)?**

( ) Yes ( ) No

**4) What communications technologies do you use for retrieving information about your distribution system? Check all that apply**

[ ] Broadband [ ] Fiber Optic [ ] Broadband Over Power-Line (BPL)

[ ] DSL/ASDL [ ] Wireless [ ] Other: ____________________

**If Wireless was selected, please choose from the drop down menu**

( ) Satellite ( ) Microwave ( ) Radio-Licensed Spectrum

( ) Cellular (2G, 3G, 4G, LTE,5G) ( ) Cell Towers ( ) Mesh (Wi-Fi)

**5) Does your utility generate reliability reports?**

( ) Yes ( ) No

**If yes, how do you share your reliability reports?**

[ ] Newspaper/Web Article [ ] Social Media [ ] Internally only

[ ] Letter to a city or PUC [ ] Not at all [ ] Other

**6) Are you required by your state utility commission or public service commission to track/report reliability?**

( ) Yes ( ) No

**1. What is your utility's definition of a sustained outage, with respect to time?**

( ) Greater than 1 minute ( ) Greater than 5 minutes ( ) Other: ______________

**2. Please input your utility's reliability statistics for each index used. The statistics will be *for the period of January 1, 2019 – December 31, 2019,* and will include MEDs and exclude planned or scheduled outages. (See Appendix for indices definition.)**

System Average Interruption Frequency Index (SAIFI) [Provide # of interruptions per year]: ________________

System Average Interruption Duration Index (SAIDI) [Provide # of minutes]: ____________________________

Average Service Availability Index (ASAI) [Provide %]: __________________________________

Customer Average Interruption Duration Index (CAIDI) [Provide # of minutes]: __________________________

**3. How do you calculate major event days (MEDs) in your utility's reliability statistics?**

( ) IEEE 1366 2.5 Beta Methodology

( ) APPA Major Event Calculation

( ) Outages are excluded when the outage severity is such that outages are no longer countable.

( ) Whenever more than X% of customers are out (please note percentage your utility applies): ____________*

( ) We do not calculate MEDs

( ) Other - Write In (Required): ____________________________________________*

**4. What is the total number of specifically tree-related outages that your utility has experienced in 2019 (enter '0' if none)? ____________________________**

**1. How does your utility capture momentary events? (check all that apply)**

[ ] Trip and Reclose sequence with no lockout

[ ] Individual trip and reclose events

[ ] Customer call-ins

[ ] Via Outage Management System

[ ] Via SCADA system

[ ] Via smart grid/smart meters/automated metering infrastructure

[ ] Other: ____________________________________________

**2. What is your yearly distribution system Momentary Average Interruptions Frequency Index (MAIFI)? (For the period January 1, 2019 – December 31, 2019.) (See Appendix for index definition.)**

MAIFI: ____________________________________________

**3. Please check the top three most common causes for momentary outages for your utility in 2019. Also, enter the number of times during the year each of the three causes occurred.**

[ ] Supply to City: ____________________________________________

[ ] Public: ____________________________________________

[ ] Natural: ____________________________________________

[ ] Equipment - Overhead: ____________________________________________

[ ] Equipment - Underground: ____________________________________________

[ ] Power Supply: ____________________________________________

[ ] Utility Human Error: ____________________________________________

[ ] Unknown/Other: ____________________________________________

**1. Do you perform power quality monitoring?**

( ) Yes ( ) No

If yes, where do you perform power quality monitoring? (check all that apply)

[ ] Residential sites [ ] Commercial sites [ ] Industrial sites

[ ] Substations [ ] Feeders/Circuits [ ] Other: ______________________

**If yes, what power quality problems are of most concern to your utility? (check all that apply)**

[ ] Voltage Sag [ ] Voltage Swell [ ] Transient (spike) [ ] Noise [ ] Flicker [ ] Total Harmonic Distortion (THD) [ ] Frequency Variation

[ ] Other: ________________________________________

**2. Has your utility experienced any power quality challenges when integrating renewables or distributed generation sources in the last three years?**

( ) Yes ( ) No

If yes, please explain:

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

**1. Has your utility recently (in the last three years) implemented any projects to help prevent outages? (check all that apply)**

[ ] Vegetation management/Tree trimming

[ ] Covered wire

[ ] Circuit rider program

[ ] Converted overhead to underground

[ ] Lightning arresters

[ ] Animal/Squirrel guards

[ ] Thermographic circuit inspections

[ ] Transformer load management

[ ] Root cause analysis

[ ] Review of worst performing circuit

[ ] Routine distribution inspection and maintenance

[ ] Other (please explain): ________________________________________

**2. Does your utility have a major storm, event or disaster plan?**

( ) Yes ( ) No

**If yes, is the plan written/documented?**

( ) Yes ( ) No

**3. Does your utility conduct regular tree trimming?**

( ) Yes ( ) No

**If yes, what is the frequency of tree trimming?**

( ) Annually ( ) Every Other Year ( ) Every Three Years

( ) Continuous ( ) Other - Write In: ____________________

**If yes, are there local regulations that limit your tree trimming policy/practice?**

( ) Yes ( ) No

**If yes, what is the approach to tree trimming?**

( ) Spot

( ) Percentage of System

( ) Other - Write In: ________________________________________

If **yes,** what percent of the tree trimming work is contracted?
(please provide a numerical value **without** the percent sign): ________________________________________

If **yes,** what is the total tree trimming cost ($) to your utility **annually?:** ________________________________________

**1. How does your utility provide 24-hour crew coverage?**

( ) 3 eight-hour shifts

( ) 2 eight-hour shifts with lineworkers on call

( ) 1 eight-hour shift with lineworkers on call

( ) Other (Please explain. i.e., do not provide twenty-four hour coverage, two twelve hour shifts etc.):

____________________________________________________________________________________________________

**2. How many lineworkers does your utility employ?**

Journeyman lineworkers: __________ Apprentice lineworkers: ______________

**Number of Contracted lineworkers?**

Total: ____________ Monthly Average: __________ Peak: _____________

**3. What is the average number of lineworkers that your utility has on a crew?**

______________________________________________________________________

**4. Do you allow crews to take utility vehicles home?**

( ) Yes ( ) No ( ) Depends (please explain): ____________________

**a. What type(s) of breakers do you use in your substation? (check all that apply)**

[ ] Vacuum [ ] SF6 [ ] Bulk Oil [ ] Minimum Oil [ ] Air Blast

**b. How many total distribution substations do you currently have in operation?**

______________________________________________________________________

**c. How many total distribution substation transformers do you currently have in operation?**

______________________________________________________________________

**d. What is the total substation transformer capacity on your distribution system (not transmission) in MVA OA (Open Air Self Cooling)?**

______________________________________________________________________

**e. Do you test transformer oil?**

( ) Yes ( ) No

**f. What is the total installed distribution (field) transformer capacity at your utility (in MVA)?**

______________________________________________________________________

**a. Do you have transformer overload guides?**

( ) Yes ( ) No

**b. Do you have an established transformer maintenance program?**

( ) Yes ( ) No

**c. Does your utility calculate its 'A' and 'B' factors?**

( ) Yes ( ) No

**If yes, does your utility use the A & B factors as part of the transformer buying process?**

( ) Yes ( ) No

**d. Does your utility use amorphous core transformers?**

( ) Yes ( ) No

**e. How would you describe your experience with the amorphous core units?**

( ) Worse than steel core ( ) Same as steel core ( ) Better than steel core

**f. Do you use different transformers for lower and higher loading factors?**

( ) Yes ( ) No

**g. What are the lowest and highest loading factors that you use to specify transformers for on your system (e.g. 0.3, 0.75, etc.)**

Lowest: ______________________ Highest: ______________________

**a. What distribution system voltages do you operate? (note all that apply)**

| | Number of Miles Overhead | Number of Miles Underground |
|---|---|---|
| 4160Y/2400 | ____________ | ____________ |
| 6900 | ____________ | ____________ |
| 8320Y/4800 | ____________ | ____________ |
| 12000Y/6930 | ____________ | ____________ |
| 12470Y/7200 | ____________ | ____________ |
| 13200Y/7620 | ____________ | ____________ |
| 13800Y/7970 | ____________ | ____________ |
| 20780Y/1200 | ____________ | ____________ |
| 22860Y/13200 | ____________ | ____________ |
| 23000 | ____________ | ____________ |
| 24940Y/14400 | ____________ | ____________ |
| 34500Y/19920 | ____________ | ____________ |
| Other: | ____________ | ____________ |

**Total Number of Miles:**

Overhead: ______________________ Underground: ______________________

**b. Does your utility perform maintenance in-house?**

( ) Yes ( ) No

**c. Does your utility use a network distribution system?**

( ) Yes ( ) No

**If yes, how many customers do you serve by networked distribution?**______________________

**d. If your utility has/uses any power systems modeling software for its distribution system (i.e. to model voltage drop, solar PV loading, conservation voltage reduction modeling, etc.) please identify software(s).**

[ ] M-Power [ ] Milsoft [ ] Cyme[ ] EPRI (GIS) [ ] Open DSS

[ ] Gridlab-D [ ] Custom spreadsheet [ ] Other/custom

**a. Please indicate the material composition that your utility generally specifies on its primary feeder cables. (check all that apply)**

[ ] Aluminum [ ] Copper [ ] Stranded [ ] Compressed stranded

[ ] Compact stranded [ ] Other: ____________________________

**b. What is the most common underground insulation used by your utility? (rank using numbers 1-4)**

| | Rank (1-4) |
|---|---|
| Tree Retardant Cross Link Polyethylene (TRXLPE) | ____________________________ |
| High Molecular Weight Polyethylene (HMWPE) | ____________________________ |
| Cross-linked Polyethylene (XLPE) | ____________________________ |
| Ethylene Propylene Rubber (EPR) | ____________________________ |
| Other | ____________________________ |

If other, please describe.

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

**c. What method do you use for installation of URD cable?**

( ) Direct Buried ( ) In Conduit

**a. Distribution system fuse philosophy:**

( ) Fuse Save (i.e. instantaneous trip first, then blow fuse.)

( ) Fuse Force (i.e. fuse blown prior to breaker operation.)

**The following questions are about reclosers. Reclosers are circuit breakers with a mechanism to automatically close the breaker after it has been opened due to a fault. They are used on overhead distribution systems to detect and interrupt momentary faults.**

**b. Typical number of recloses to lockout: __________________**

**c. Open duration prior to reclosure (in seconds) (if using current-sensing to set open duration, put 'tc' in the field):**

| | Commercial/Industrial Feeder/Circuit | Residential Feeder/Circuit |
|---|---|---|
| 1st | ______________________ | ______________________ |
| 2nd | ______________________ | ______________________ |
| 3rd | ______________________ | ______________________ |
| 4th | ______________________ | ______________________ |

**a. What types of fault signals do your fault indicators use? (check all that apply)**

[ ] LED indication  [ ] Sound  [ ] Mechanical flag  [ ] Manual or auto reset

[ ] Other: ____________________  [ ] None

**b. How does your utility sectionalize faulted sections of cable? (check all that apply)**

[ ] Fuse  [ ] Section by Section  [ ] Phase Stick

[ ] High Pot  [ ] Other: _________________________

**c. How does your utility locate faults? (check all that apply)**

[ ] Thumper  [ ] Radar/TDR Device  [ ] Other: _______________________

**d. If your utility uses fault indicators, please indicate the typical system characteristics where they are used below:**

( ) Overhead  ( ) Underground

( ) Both  ( ) Other: ______________________________________________

**A. Do your easements, or property rights, include: (check all that apply).**

[ ] Right to construct, maintain, operate, replace, upgrade, or rebuild pole lines or underground cable and appurtenances thereto

[ ] Right of ingress and egress

[ ] Right to trim and remove all trees on or adjacent to the easement strip necessary to maintain proper service

[ ] Right to keep easement strip free of any structure or obstacle which the company deems a hazard to the line

[ ] Right to prohibit excavation within 5 feet of any buried cable, or any change of grade which interferes with the cable

[ ] Right to install overhead or underground necessary wiring for street lighting that is requested and/or required, but no more than 5 feet from any lot time

[ ] Other - Please Explain: ______________________________________________*

**B. Does your utility have cable in the right-of-way and/or front easement?**

[ ] Yes [ ] No

**C. Does your utility have side yard and/or front yard easements? (Check all that apply)**

[ ] Side yard [ ] Front yard

**D. Does your utility have codes/standards for construction and installation practices? (Check all that apply)**

[ ] Utility has own set of codes [ ] RUS standards are used [ ] State codes

[ ] NESC [ ] None [ ] Other:

**1. For new underground subdivisions, excluding house services, please check how your utility charges customers (select one):**

( ) No charge

( ) Full cost of installation

( ) Per specific design

( ) Flat fee

( ) Differential cost (underground vs overhead)

( ) Bill on actual costs

( ) Estimated costs

( ) Depends: ______________________________________________

( ) Other, please describe: ______________________________________________

**1. On an existing service that is to be converted from overhead to underground service, does your utility charge?**

( ) Yes ( ) No

**1. Does your utility allow cable/telephone service wires in your house service trench?**

( ) Yes ( ) No

**If yes, is there a charge?**

( ) Yes ( ) No

**2. In new construction, can overhead be installed or is it mandatory to be underground?**

( ) Can be overhead ( ) Mandatory to be underground

**1. Does your utility have an initiative to convert existing overhead lines to underground?**

( ) Yes ( ) No

If **yes,** this initiative is:

( ) Voluntary ( ) Mandatory

If Mandatory, how is it funded?: ____________________

**1. Does your utility install sub-grade equipment? (ie. Transformers, switchgear)?**

( ) Yes ( ) No

**2. Do you allow housing developers to install any facilities?**

( ) Yes ( ) No

If **yes,** where?

( ) Complete underground system ( ) Conduit and ground sleeves only

( ) Sub-surface infrastructure ( ) Other: ____________

**3. Does your utility standardize the size of the following? (check all that apply)**

[ ] Substations [ ] Substation transformers [ ] Field transformers

**4. For new residential construction, what is the standard distribution transformer installed (size) and how many customers are typically connected?**

Transformer size (in kVA): ____________________

Customers connected: ____________________

**5. What is your utility's clearance policy? (The intent of the question is to see whether your utility follows the NESC code regarding clearances (Section 23) or whether you have created your own policies for clearances when constructing new lines.)**

______________________________________________________________

**1. Utility Peak Load (Distribution System)**

*(For January 1, 2019 – December 31, 2019)*

*(in MW):* ____________________

**2. For the period January 1, 2019 - December 31, 2019, please provide the average number of customers below:**

Residential: ____________________

Commercial: ____________________

Industrial: ____________________

Total: ____________________

**3. What is your service area in square miles?**

__________________________________

**4. Predominate Load Concentration (if your city has no definition of urban, it is defined for this survey as areas of cities that have an overall average density of at least 500 people per square mile):**

Urban (%): __________ Rural (%): ____________

**5. Please provide the number of vehicles your utility has in its fleet that are less than or equal to one ton?**

**6. Please provide the number of vehicles your utility has in its fleet that are greater than one ton?**

_______________________

**7. What is your utility's Energy Information Administration ID number? (used when submitting EIA Form-861)**

_______________________

**1. What is your utility's involvement in APPA's RP3 Program?**

( ) Currently an RP3 designated utility

( ) Currently an RP3 designated utility and applying for re-designation

( ) Currently applying for first-time RP3 designation

( ) Not involved in RP3 program

**Comments:**